PB83-172478

Petroleum Pipeline Leak Detection Study

Science Applications, Inc.
El Segundo, CA

Prepared for

Municipal Environmental Research Lab.
Cincinnati, OH

Mar 82

U.S. Department of Commerce
National Technical Information Service
NTIS

PB83-172478

EPA-600/2-82-040
March 1982

PETROLEUM PIPELINE LEAK DETECTION STUDY

by

John R. Mastandrea
Science Applications, Inc.
101 Continental Blvd.
El Segundo, CA 90245

Contract No. 68-03-2532

Project Officer

J. S. Dorrler and R. A. Griffiths
Solid and Hazardous Waste Research Division
Oil and Hazardous Materials Spills Branch
Municipal Environmental Research Laboratory-Cincinnati
Edison, New Jersey 08837

REPRODUCED BY
NATIONAL TECHNICAL
INFORMATION SERVICE
U.S. DEPARTMENT OF COMMERCE
SPRINGFIELD, VA. 22161

MUNICIPAL ENVIRONMENTAL RESEARCH LABORATORY
OFFICE OF RESEARCH AND DEVELOPMENT
U.S. ENVIRONMENTAL PROTECTION AGENCY
CINCINNATI, OHIO 45268

TECHNICAL REPORT DATA
(Please read Instructions on the reverse before completing)

1. REPORT NO. EPA-600/2-82-040	2. ORD Report	3. RECIPIENT'S ACCESSION NO. PB83 172478
4. TITLE AND SUBTITLE Petroleum Pipeline Leak Detection Study		5. REPORT DATE March 1982 6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S) John R. Mastandrea		8. PERFORMING ORGANIZATION REPORT NO.
9. PERFORMING ORGANIZATION NAME AND ADDRESS Science Applications, Inc. 101 Continental Blvd. El Segundo, CA 90245		10. PROGRAM ELEMENT NO. 1NE 826 11. CONTRACT/GRANT NO. 68-03-2532
12. SPONSORING AGENCY NAME AND ADDRESS Municipal Environmental Research Laboratory- Cin., OH Office of Research and Development U.S. Environmental Protection Agency Cincinnati, OH 45268		13. TYPE OF REPORT AND PERIOD COVERED Final 14. SPONSORING AGENCY CODE EPA/600/14

15. SUPPLEMENTARY NOTES

J. S. Dorrler, R. A. Griffiths: Project Officers (201-321-6629)

16. ABSTRACT

This study reviews and analyzes the U.S. petroleum pipeline system, accidental spills, and spill prevention programs. It concludes that improved pipeline spill prevention measures are needed, because pipeline systems are aging, population densities near lines are increasing dramatically, and new lines are expected to be larger and longer.

An approach to developing a spill prevention program is presented. Then, recommended spill prevention programs for individual pipeline systems are described. These programs consist of scheduled inspection and/or leak detection methods and are shown to be capable of significantly reducing the risk of serious spills. Practical considerations such as the cost of inspections and spillage are also included.

This effort involved two tasks: (1) proper assessment of the risk, and (2) selection of optimum prevention measures. This report solves two problems that formerly prevented the accomplishment of these tasks. First, the contribution of pipeline age, dimension, etc., to the overall risk could not be assessed, primarily because of limitations in reported pipeline leak data and lack of a comprehensive analysis measures for reducing the risk (frequency, volume, and the combined frequency and volume of spills) was not previously available.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Petroleum pipelines Pipeline transportation Leak detectors	Pipeline risk analysis Leak detection	

18. DISTRIBUTION STATEMENT RELEASE TO PUBLIC	19. SECURITY CLASS *(This Report)* UNCLASSIFIED	21. NO. OF PAGES 472
	20. SECURITY CLASS *(This page)* UNCLASSIFIED	22. PRICE

EPA Form 2220-1 (9-73)

NOTICE

Mention of trade names or commercial products does not constitute endorsement or recommendation for use.

BEGIN FIRST LINE OF TEXT HERE
CENTER OF PAGE
TOP OF IMAGE AREA
DROPPED HEAD, BEGIN SECTIONS HERE

FOREWORD

The U.S. Environmental Protection Agency was created because of increasing public and government concern about the dangers of pollution to the health and welfare of the American people. Noxious air, foul water, and spoiled land are tragic testimonies to the deterioration of our natural environment. The complexity of that environment and the interplay of its components require a concentrated and integrated attack on the problem.

Research and development is that necessary first step in problem solution; it involves defining the problem, measuring its impact, and searching for solutions. The Municipal Environmental Research Laboratory develops new and improved technology and systems to prevent, treat, and manage wastewater and solid and hazardous waste pollutant discharges from supplies, and to minimize the adverse ecomonic, social, health, and aesthetic effects of pollution. This publication is one of the products of that research and provides a most vital communications link between the reseacher and the user community.

This study investigates spill prevention programs for petroleum pipeline systems. The results of the study can be utilized both in assessing the need and in the actual development of a spill prevention and control program for individual pipelines and those nationwide. The report should be of particular value to research users involved in the prevention of accidental spills from petroleum pipleline systems. For further information on the subject contact the author directly or the Applied Mechanics Division of Science Applications, Inc.

Francis T. Mayo, Director
Municipal Environmental Research
Laboratory

PAGE NUMBER
TYPING GUIDE SHEET

ABSTRACT

In this study, oil spills from petroleum pipeline systems are investigated and spill prevention programs presented. The study includes an extensive review and analysis of the U.S. petroleum pipeline transportation system, accidental spills nationwide and the available means of effectively preventing spills.

A current need for improved spill prevention measures for petroleum pipelines is identified. This situation exists because of the potential of serious spills. Furthermore, since existing petroleum pipeline systems are aging, population densities near many new lines are increasing dramatically, and new lines are expected to be larger and longer, the need for such spill prevention programs is expected to increase.

Spill prevention programs developed in this report involved the following two tasks: (1) proper assessment of the risk; and (2) selection of optimum spill prevention measures to adequately minimize the risks. Prior to this study, both tasks could not be achieved for most petroleum pipeline systems because of two main problems. First, the contribution of all the significant factors, i.e., pipeline age, dimension, etc., to the overall oil spill risk previously could not be assessed primarily because of limitations in reported pipeline leak data and lack of a comprehensive analysis of the nationwide spill problem. The complexity of the petroleum pipeline system in the United States, i.e., system consists of many individual lines of various dimensions, age, controls, etc., further complicated this assessment because there is limited information on the variations between individual pipeline systems. Secondly, an assessment of all viable spill prevention measures for reducing the risk (frequency, volume, and the combined frequency and volume of spills) was not previously available. These tasks and problems are addressed successfully in this study.

An approach for developing a spill prevention program is presented. Then recommended spill prevention programs for various types of individual petroleum pipeline systems and those nationwide are described. Using certain programs, spill reductions of 75 percent or more are expected. These programs consist of scheduled inspection and/or leak detection methods used alone or in various combinations, and are shown to be capable of achieving significant levels of reduction in the risk of serious spills. Practical considerations such as the cost of inspections and spillage are also included. Means are provided so that individual programs can be readily developed by operators for their specific individual lines.

EPA Form 2350-4 (4-00)
TYPING GUIDE SHEET

CONTENTS

Foreword iii
Abstract iv
Figures vii
Tables xi
Abbreviations and Symbols xvii
Metric Conversion Factors xix
Acknowledgment xx

1. Introduction 1
2. Conclusions 4
3. Recommendations 5
4. Petroleum Transport - Systems, Measurement, Changes and Losses . 9
    4.1 Petroleum transportation system description 11
    4.2 Petroleum system - losses and specific loss mechanisms . . . 39
    4.3 Measurement 48
    4.4 Changes in petroleum between receipt and delivery 64
    4.5 Total measurement system error 65
    4.6 Loss statistics 66
    4.7 Total petroleum losses--pipeline systems 145
5. Pipeline System Leak Detection and Inspection Methods 146
    5.1 General discussion 146
    5.2 General description of methods 150
    5.3 Compendium of leak detection and inspection methods 155
    5.4 Status 195
6. Analysis of the Risk of Accidental Oil Spills from Petroleum Pipeline Systems 223
    6.1 Seriousness of oil spills 223
    6.2 Problems in assessing the oil spill risk 225
    6.3 Analysis and assessment of the risk of accidental spills . . 231
7. Analysis of the Reduction of Oil Spills from Line Pipe by Utilization of Leak Detection and Inspection Methods 271
    7.1 Comparison and evaluation of leak detection and inspection methods 272
    7.2 Oil spillage that potentially can be prevented using the selected leak detection and inspection methods 297
    7.3 Cost analysis 309
    7.4 Cost-effectiveness analysis 322
8. Recommendations 327
    8.1 Discussion 327
    8.2 Benefits 329
    8.3 Recommended preventive maintenance program 329
    8.4 Recommended developmental and new inspection and leak detection methods 335

TYPING GUIDE SHEET

References 337

Appendices

A. Existing U.S. and foreign regulations for transportation of liquids by pipeline 344
B. Pipeline mileage data 380
C. Summary of liquid pipeline accident reports on DOT form 1000-1 compiled by the Office of Pipeline Safety for years 1969-1976 398
D. A statistical estimate of pipeline leakage 416
E. Methodology 440

TYPING GUIDE SHEET

FIGURES

Number		Page
1	Petroleum transportation system	12
2	Petroleum transportation model	13
3	Flowsheet of petroleum production operations	14
4	A pipeline system composed of gathering, trunk and distribution lines	21
5	Growth of crude oil pipelines in the United States	24
6	Mileage of petroleum pipelines in the United States	25
7	Illustrative operating conditions: Trans-Alaska Pipeline	32
8	Standard Federal regions (Commerce, EPA and HUD), with number of liquid pipeline accidents	37
9	Petroleum administration for Defense and Bureau of Mines refining districts	38
10	Major system components for crude losses between supply and refinery input	40
11	Fault tree A_1, oil spilled from petroleum pipeline system	43
12	Fault tree C_1, spill from pipelines	44
13	Curves for estimating volume change when blending volatile hydrocarbons with crude oil	47
14	Typical system for delivery to pipeline	50
15	Typical PD meter LACT unit flow diagram	51
16	PD meters	52
17	Typical accuracy curve for a PD meter	58
18	Error curves and calculations for inaccurate correction factors of the coefficient of expansion α for liquids	62

19 Minimum detectable spill loss for a simple pipeline system 67

20 Spill incidents and volume versus year for petroleum pipeline system accidents reported to OPSO between 1968-1976 77

21 Number of incidents versus year of occurrence for carrier system components 80

22 Volume of spill versus year of occurrence for carrier system components 81

23 Number of spills versus year of occurrence by cause . . . 84

24 Volume of spills versus year of occurrence by cause . . . 85

25 Percentage of number and volume of spills by cause for line pipe 88

26 Number of incidents versus year of occurrence for type of fluid transported in pipeline system accidents reported to OPSO between 1968-1976 91

27 Volume of spills versus year of occurrence for type of fluid transported through pipeline system accidents reported to OPSO between 1968-1976 92

28 Number of incidents versus year of occurrence for type of fluid transported in line pipe, accidents reported to OPSO between 1971-1975 94

29 Spill incidents and spills per 1000 miles versus year for pipeline system accidents reported to OPSO between 1968-1976 97

30 Spill volume for mileage and throughput versus year for pipeline system accidents reported to OPSO between 1968-1976 98

31 Spill incidents per 1000 miles and spill volume per mile versus year for line pipe transporting liquids in the U.S. reported to OPSO between 1971 and 1975 101

32 Size distribution of spills from U.S. terrestrial pipelines transporting liquids 104

33 Mean spill size and line pipe diameter for line pipe accidents reported to OPSO, 1971-1975 107

34 Mean spill versus line pipe diameter for line pipe accidents in the U.S. reported to OPSO between 1971-1975 108

35 Frequency of spills for pipeline diameters and mileage for line pipe accidents in the U.S. Reported to OPSO between 1971-1975 109

36 Spill volume for petroleum pipeline diameters of line pipe accidents reported in the U.S. to OPSO between 1971-1975 110

37 Diameter of line pipe and causes of spill incidents for accidents reported to OPSO in 1971 114

38 Spill incidents by year of pipeline system installation for accidents reported to OPSO between 1971-1975 117

39 Pipeline system spill incidents per 1000 miles of pipeline by the year of pipeline system installation for accidents reported to OPSO between 1971-1975 118

40 Line pipe spill incidents per 1000 miles of pipeline by the year of pipeline system installation for accidents reported to OPSO between 1971-1975 121

41 Age of line pipe and causes of spill incidents per 1000 miles of line pipe for accidents reported to OPSO in 1971 and 1974 122

42 Damage from petroleum pipeline system incidents reported to OPSO between 1968-1978 for crude and product 127

43 Number and volume of 10 to 50-barrel spills by year, 1971-75, Gulf of Mexico outer continental shelf 129

44 Discharge trends for oil only for calendar years 1970-1975 130

45 Pipe and petroleum pipeline system oil spills in the U.S. for gathering/distribution and production systems in the United States between 1970-1971 140

46 Cross-country pipeline mean spill size versus pipe diameter 143

47 Cumulative size distribution for oil industry cross-country pipeline spills, Western Europe and Canada (assorted pipe diameters) 144

TYPING GUIDE SHEET

48 Transportation accidents in 1975, National Transportation Safety Board 1975 226

49 Fatalities and injuries versus amount of product loss in liquid pipeline systems accidents 228

50 Symbolism for fault trees 235

51 Fault trees, V_{ST} and F_{ST}, spill frequency and volume from typical section of line (reference line) 236

52 Relative measure of risk of oil spilled from typical section of line (reference line)--leaks, ruptures, mean . . 241

53 Fault tree, DE_{ST}, spill damage external to typical section of line pipe (reference line) 243

54 Correction factors for frequency of spills--age, geometry, length, use, size 245

55 Fault tree, CF_F, correction factors for frequency of spills 246

56 Fault tree, CF_{SV}, correction factor for the volume of spills 252

57 Correction factors for volume of spills--diameter, length, use, shutdown time 253

58 Fault tree, CF_{VR} or CF_{VM}, correction factors for spill size--rupture and mean 257

59 Fault tree, CF_{ED}, correction factors for risk of spill damage external to line pipe 259

60 Fault trees, V_{STC} and F_{STC}, frequency and mean volume of spills from line pipe 262

61 Fault trees, V_{NLLC}, V_{NLRC}, V_{MC}, nominal largest size of ruptures, leaks and mean for line pipe spills 264

62 Fault trees, RMR_R, RMR_L, relative measure of risks (barrels/year) of ruptures and leaks from line pipe 266

63 Fault tree, RMR_M, relative measure of risk (barrels/year) of mean spills from line pipe 267

TABLES

Number Page

1 Percentage of Petroleum Moved by Transportation Modes . . . 11

2 Percentage of Crude Petroleum and Petroleum Products Moved by Method of Transportation, 1938-1974 16

3 Volume of Oil Produced and Imported, 1972-1977 17

4 Offshore Production of Crude Petroleum 18

5 Volume of Petroleum Transported by Pipelines in the United States 19

6 Volume and Type of Oil Transported by Interstate Pipeline Systems 20

7 Pipeline Transportation System and Associated Subsystems . 22

8 Pipeline Mileage in the United States - Total and Interstate 26

9 Mileage of Petroleum Pipelines by Diameter in the United States, January 1, 1971 and January 1, 1974 27

10 Mileage of Petroleum Pipelines by Diameter in the United States, January 1, 1971 and January 1, 1968 28

11 Relationship between Pipe Diameter, Length, and Volume Contained Inside 29

12 Petroleum Pipeline System Mileage in the U.S., by Year Installed 31

13 Analysis of Crude Products Reported to NPC 33

14 Analysis of Clean Products Reported to NPC 34

15 Pipeline Fill for Petroleum Pipelines in the United States January 1, 1977 and January 1, 1974 36

EPA Form 2350-4 (4-80)

TYPING GUIDE SHEET

16 Throughput and Losses from ICC Transport Statistics 69

17 Petroleum Loss Allowance from Typical U.S. Pipeline Companies in Percent of Gross Petroleum Shipped 71

18 Spill Statistics for Pipeline Systems Transporting Liquids in the U.S. for Incidents Reported to OPSO Between 1968-1976 78

19 Number and Volume of Spills for Failures of Petroleum Pipeline System Components (In Percent of Total) 79

20 Number and Volume of All Spillage Incidents (In Percent) for All Pipeline System Components, By Cause Reported to OPSO Between 1971 and 1975 83

21 Number, Volume and Percentage of All Spillage Incidents for Line Pipe, By Cause Reported to OPSO Between 1971 and 1975 87

22 Spill Volume and Incidents for Accidents Reported to OPSO Between 1968 and 1976 for Crude and Produce Pipeline Systems 90

23 Statistical Estimate of Annual Distribution of Petroleum Spill Frequencies and Barrels Lost from Line Pipe for Crude and Product 95

24 Spill Data Summary for Petroleum Pipeline Systems Transporting Liquids in the U.S. for Accidents Reported to OPSO Between 1968-1976 96

25 Spill Data Summary for Line Pipes Transporting Liquids in the U.S. for Accidents Reported to OPSO Between 1971-1975 100

26 Annual Spill Statistics for Line Pipes Transporting Liquids in the U.S. for All Spill Sizes 100

27 Spill Incidents of Pipeline System for Two Pipeline Diameter Categories for Accidents Reported to OPSO Between 1971-1975 103

28 Summary of Spill Data for Line Pipe Diameters for Liquid Pipeline Accidents Reported to OPSO Between 1971-1975 . 106

29 Outside Force Incidents on Line Pipe Reported in the U.S. to OPSO Between 1971-1974 111

EPA Form 2350-4 (4-80)
TYPING GUIDE SHEET

30 Fault Incidents from Line Pipe Reported in the U.S. to OPSO Between 1971-1974 112

31 Spill Incidents for Pipeline System Age and Estimated Mileage for Accidents Reported to OPSO Between 1971-1975 116

32 Spill Incidents and Volume for Line Pipe Age for Accidents Reported to OPSO Between 1971 and 1979 119

33 Number of Outside Force Incidents by Depth of Cover 123

34 Fatalities and Injuries for Petroleum System Incidents Reported to OPSO Between 1968 and 1976 124

35 Damage from Petroleum Pipeline Systems in the U.S. for Incidents Reported to OPSO Between 1968-1976 126

36 Number and Volume of Spills Each Year, 1971-1975, Gulf of Mexico Outer Continental Shelf 128

37 General Areas and Locations of Spillage in and About U.S. Waters, Reported to USCG in 1975 132

38 Causes of Spills in and About U.S. Waters, Reported to USCG in 1975 133

39 Sources of Spills in and About U.S. Waters, Reported to USCG in 1975 134

40 Component Versus Quantity Spill Category for Gathering/ Distribution System, 1970-1971 135

41 Component Versus Quantity Spill Category for Drilling System, 1970-1971 136

42 Component Versus Quantity Spill Category for Production System and All Systems, 1970-1971 137

43 Source Data Summary 138

44 Cross-Country Spill Data for Western Europe 141

45 Summary of Type and Operational Mode of Leak Detection and Inspection Methods 159

46 Visual and Aided Visual Line Observations 161

47 Oil Spill Detectors on or Near the Water 163

EPA Form 2360-4 (4-80)

TYPING GUIDE SHEET

48 Internal Fluid Variations During Transfer 165

49 Detection and Location of Leaked Oil on or at a Short Distance from Pipeline 168

50 Periodic Pressure Tests 171

51 Corrosion Inspection 174

52 Standard Nondestructive Inspection 175

53 Pipeline Inspection Pigs 177

54 Survey-Pipeline System Charting and Depth of Burial 180

55 Miscellaneous 182

56 Assumptions for Typical Section of Line Pipe (Reference Line) 234

57 Relative Risk of Oil Spills from a Typical Section of Line Pipe 240

58 Correction Factors for Risk of Spill Damage External to Line Pipe 258

59 Calculation of the Frequency F_{STC} and Volume V_{STC} of Spills for Line Pipe 261

60 Calculations of the Nominal Largest Size of Ruptures, V_{NLRC}, Leaks$_{NLLC}$ and Mean V_{MC} for Line Pipe Spills . . . 263

61 Calculations of the Relative Measure of Oil Spill Risks for Rupture RMR_R, Leaks RMR_L and Mean Size RMR_M Spills for Line Pipe 265

62 Calculations of the Correction Factor CF_{ED} for Risks External to Line Pipe 268

63 Calculations of Risks External to Line Pipe 269

64 Inspection and Leak Detection Methods Selected for Further Evaluation of Line Pipe 274

65 Comparison of the Selected Methods for Detection and Location of Reference Line Leaks and Ruptures 277

66 Spill Reduction Analysis for Volume of Ruptures for Typical Section of Line Pipe 280

EPA Form 2360-4 (4-80)

TYPING GUIDE SHEET

67 Spill Reduction Analysis for the Volume of Leaks for a Typical Section of Line Pipe 284

68 Reduction Analysis for the Frequency of Oil Spills by Cause for a Typical Section of Line Pipe (Reference Line) 290

69 Spill Reduction Analysis for the Frequency of Leaks for A Typical Section of Line Pipe 294

70 Spill Reduction Analysis for the Frequency of Ruptures for a Typical Section of Line Pipe 296

71 Summary of Risk Reduction Factors for Selected Inspection and Leak Methods 298

72 Analysis of Oil Spilled from the Reference Line that Can be Prevented or Go Undetected 304

73 Analysis of Oil Spillage that Can be Prevented or Go Undetected for All U.S. Lines 307

74 Assumptions for Reference Line 311

75 Equipment and Inspection Service Costs for Selected Leak Detection and Inspection Methods 312

76 Cost of Inspection and Leak Detection Methods 313

77 Offshore Pipeline Construction Costs 316

78 Spill Cleanup Cost Factors as a Function of the Location of Spill 321

79 Cost-Effectiveness Analysis for All U.S. Lines 323

80 Preventive Maintenance Schedules for the Reduction of the Frequency of Accidental Spills from Line Pipe 331

81 Preventive Maintenance Schedules for the Reduction of the Volume of Accidental Spills from Line Pipe 332

82 Preventive Maintenance Schedules for the Reduction of the Frequency and Volume of Accidental Spills from Line Pipe 333

EPA Form 2350-4 (4-80)

TYPING GUIDE SHEET

ABBREVIATIONS AND SYMBOLS

atm -- atmosphere
bbl -- barrel
bbld -- barrels per day
bblh -- barrels per hour
bblm -- barrels per minute
°C -- degrees Centigrade
cm -- centimeter
dwt -- dead weight ton
°F -- degrees Fahrenheit
ft -- foot
g -- gram
gal -- gallon
gpd -- gallons per day
gph -- gallons per hour
gpm -- gallons per minute
hr -- hour
in -- inch
IR -- infrared
kg -- kilogram
km -- kilometers
l -- liter
lb -- pound
LNG -- liquified natural gas
LPG -- liquified petroleum gas
m -- meter
mg -- milligram
mi -- miles
min -- minute
ml -- milliliter
mm -- millimeter
oz -- ounce
psi -- pounds per square inch
UV -- ultraviolet
vol -- volume
wt -- weight
yr -- year

SYMBOLS

% -- percent
/ -- per

AGA -- American Gas Association
API -- American Petroleum Institute
BLM -- Bureau of Land Management
BOM -- Bureau of Mines
BS&W -- Bottom Sediment and Water Content
CEQ -- Council on Environmental Quality
DnV -- Det Norske Veritas
DOA -- Department of the Army
DOE -- Department of Energy
DOT -- Department of Transportation
DWP -- Deepwater Port
EMAT -- Electromagnetic Non-Contact Transducer
EPA -- Environmental Protection Agency
ERDA -- Energy Research and Development Administration
FOA -- Food and Agriculture Organization
FEA -- Federal Energy Administration
GAO -- General Accounting Office
HUD -- Housing and Urban Development
ICC -- Interstate Commerce Council
IMCO -- International Maritime Consultative Organization
IP -- Institute of Petroleum, Great Britain
LACT -- Lease Automatic Custody Transfer Systems
LPG -- Liquid Petroleum Gas
NBS -- National Bureau of Standards
NDI -- Nondestructive Inspection
NOAA -- National Oceanic and Atmospheric Administration
NPC -- National Petroleum Council
NTIS -- National Technical Information Service
OCS -- Outer Continental Shelf
OPSO -- Office of Pipeline Safety and Operations
PAD -- Petroleum Administration for Defense
PD -- Positive Displacement Meters
PIRS -- Pollution Incident Reporting System
PVTT -- Pressure-Volume-Temperature-Time
SAI -- Science Applications, Inc.
SPCC -- Spill Prevention, Control and Countermeasures
TM -- Turbine Meters
US -- United States
USCG -- United States Coast Guard
USDA -- United States Department of Agriculture
USDI -- United States Department of Interior
USGS -- United States Geological Survey
USN -- United States Navy

METRIC CONVERSION FACTORS

Approximate Conversions to Metric Measures

Symbol	When You Know	Multiply by	To Find	Symbol
		Length		
in	inches	2.5	centimeters	cm
ft	feet	30	centimeters	cm
yd	yards	0.9	meters	m
mi	miles	1.6	kilometers	km
		Area		
in^2	square inches	6.5	square centimeters	cm^2
ft^2	square feet	0.09	square meters	m^2
yd^2	square yards	0.8	square meters	m^2
mi^2	square miles	2.6	square kilometers	km^2
		Mass (weight)		
oz	ounces	28	grams	g
lb	pounds	0.45	kilograms	kg
	short tons (2000 lb)	0.9	tonnes	t
		Volume		
fl oz	fluid ounces	30	milliliters	ml
qt	quarts	0.95	liters	l
gal	gallons	3.8	liters	l
ft^3	cubic feet	0.03	cubic meters	m^3
		Temperature (exact)		
^oF	Fahrenheit temperature	5/9 (after subtracting 32)	Celsius temperature	^oC

ACKNOWLEDGEMENTS

The objective of this project could not have been accomplished without the assistance of numerous individuals in the oil and gas industries, Federal and State Government, trade associations, engineering companies, universities and others. These individuals, dedicated to doing their best to insure both safety and pollution prevention in petroleum pipeline systems, graciously responded to inquiries, personnel interviews, provided facility visits and supplied information requested. Science Applications, Inc. wishes to convey its sincere appreciation for their efforts.

In particular, Science Applications, Inc. wishes to acknowledge the support and contributions of the following individuals and organizations:

American Petroleum Institutes
American Gas Association
Atlantic Richfield Oil Co.
Chevron Oil Company
Det norske Veritas
Exxon Research and Engineering Co.
Gulf Oil
Getty Oil Company
International Research and Technology Corp.
Mobil Oil Company
National Transportation Safety Board
Oil Companies' International Study Group (CONCAWE)
Pipeline Digest
Shell Pipe Line Corporation
U.S. Department of Energy - Bureau of Mines
U.S. Department of Interior - Bureau of Mines
U.S. Department of the Interior - Geological Survey
U.S. Department of Transportation - Office of Pipeline Safety and Operations
U.S. Department of Transportation - Office of Deepwater Ports
U.S. Department of Transportation - Transportation Systems Center.

Science Applications, Inc. would like to give special thanks to Mr. J. S. Dorrler, Project Officer of the U.S. Environemntal Protection Agency, for his guidance and valuable discussions and comments on the entire project and to Mr. R. A. Griffiths, who succeeded Mr. Dorrler in the latter phases of this project, for his help and support.

SECTION 1

INTRODUCTION

Transportation of petroleum through pipeline systems in the United States is relatively safe. However, with the many individual systems of diverse dimension, age, material, etc., a real and continuous concern exists over accidents and leakage[1]. Petroleum accidents and leakage cause many pollution incidents that are detrimental to both national interest and the oil industry. These accidents result in the loss of large quantities of petroleum, cause significant environmental problems, and subject segments of the population to potential hazards. Even small losses from a pipeline system cannot be tolerated, and it is the responsibility of government and operating companies to protect the community from possible damage resulting from a leak.

OBJECTIVES

This study had the overall objective of providing a viable, cost-effective means of reducing oil spill incidents and volume and thereby minimizing environmental impacts. Specific objectives included: (1) estimate total petroleum losses and specific loss mechanisms; (2) accurately appraise oil spill incidents including causes, system component failures, frequency and volume of spills, causes and key factors relating to spills; (3) define capabilities of leak detection and/or inspection techniques both to detect leaks and determine the condition of the line; (4) estimate oil spillage that potentially can go undetected; and (5) if feasible and practical, develop or recommend advanced techniques for reducing the problem.

The envisioned result of this study is the development of an effective spill prevention program for individual pipeline systems of diverse age, dimensions, controls, etc. The program would be based on scheduled inspections and/or leak detection to test the condition of pipelines and/or to check for the presence of leaks. The envisioned application is to aid operating companies both in evaluating the need and in the actual development of a spill prevention and control program for individual lines. In addition, such information might aid various local and Federal agencies in evaluating problem areas and available means of minimizing the problem.

SUMMARY

To obtain an overall perspective of the problem of accidental spills from petroleum transportation systems, the extent and nature of petroleum losses from the petroleum transportation systems were studied (Section 4). Estimates were made of the total quantity of petroleum lost and the amount attributable to each major loss mechanism. Emphasis was directed to the problem of spills from the transmission line (line pipe). This section also provides basic information that was used in the detailed analysis of the oil spill risks (see Section 6) and the capabilities or methods to reduce the risk (see Section 7).

Leak detection and inspection methods for petroleum pipeline systems that might reduce the risk of oil spillage (i.e., reduce frequency of spills or limit the volume of oil lost) are presented in Section 5. Because of the high incidence of pipeline spills and the potential for significant reductions of the oil spill risks, major emphasis was given to detection and prevention of leaks from line pipe failures. However, methods were also included for other pipeline system components. Methods for prevention of leakage by detection of impending failures and minimizing of leakage volume through early detection of leakage were emphasized. Methods included in existing domestic and foreign regulations and current recommended practices for inspection and leak detection of liquid and gas pipeline systems were reviewed.

An analysis of the risk of accidental oil spills from petroleum pipeline systems is presented in Section 6. The seriousness of oil spills and difficulties in assessing the risk of oil spills were reviewed. Approaches accounting for these difficulties are presented and an analysis and assessment of the risk of oil spills is given. Both the risk of oil spill from a system and environmental problems created by spillage were examined. An in-depth analysis of the risk of oil spills from line pipe was carried out. An analysis was performed on a reference line (typical line), and correction factors for variations from the reference line were developed so that the spill risk (potential) could be estimated for most lines. Simplified tables and figures are provided so that an operator can estimate the spill potential of his own line.

The potential of selected leak detection and inspection methods[a] to reduce the risk of oil spills (frequency and volume of spills and risks external to the line) from petroleum pipeline systems are estimated in Section 7. Means are provided for an operator to estimate the risk of oil spills and the risk reduction capabilities (effectiveness) of inspection and leak detection methods for his own line. Estimates were made of the capabilities of leak detection and inspection equipment to detect a leak of a certain magnitude and/or impending failures. The methods were evaluated based on their capability to reduce the frequency and volume of leak-type and rupture-type spills for the reference line. Factors were established that provide a simple means of comparing the capability of methods to reduce the frequency and volume of spills. These factors aid a potential user in selection of the most suitable method that will satisfy the spill prevention program needs of a particular line. Since costs are a major consideration in a practical maintenance program for line pipe, costs of the various options and spillage are estimated and a cost-effectiveness analysis is presented.

---

[a] Selected methods were those judged to be capable of achieving a significant reduction in the spill risk.

Preventive maintenance programs for line pipe are presented and particular programs are recommended in Section 8. Benefits of these programs are discussed. Preventive maintenance schedules for achieving specified reductions in the frequency of spills, the volume of spills and the combination of frequency and volume of spills are identified. Recommendations were based primarily on qualitative estimates of both the oil spill risks that exist and the capabilities of various methods to reduce the risks. However, the recommendations were also based on other practical considerations such as cost of inspections and spillage.

SECTION 2

CONCLUSIONS

This study indicates that the potential exists for serious spills from the line pipe of petroleum pipeline systems and that various options, inspection and leak detection methods, are available to significantly reduce the oil spill risk. Based on the results of this investigation, preventive maintenance programs for line pipe are recommended.

The component of a pipeline system most responsible for spill incidents for the largest loss of petroleum, and for the greatest risk to the environment is the operational transmission line. As pipeline systems age, an even higher incidence of pipeline failures is anticipated. Once a line becomes operational, however, no guidelines and/or schedules for effective inspection exist for U.S. pipeline systems. Furthermore, state-of-the-art leak detection methods are not commonly used. Even if used, most methods are limited in sensitivity, and significant quantities of fluid may be lost before shutdown. The problem becomes particularly critical for certain pipelines such as those of large diameter (36- to 54-in), underwater lines, old lines, etc. In the case of large-diameter lines, high volumes of oil can be spilled before conventional leak detection systems can detect the leak and initiate shutdown.

Although no methods or procedures exist that can guarantee complete protection against a pipeline leak, it is possible that the frequency and severity of spill incidents can be minimized by effective and frequent inspection of the operational line. Certain identified inspection and/or leak detection methods used alone or in various combinations may be effective in minimizing the risk of a serious spill from individual lines. In many instances, the various available options may be practical, beneficial, and cost-effective. Furthermore, preventive maintenance programs can be implemented (at significant costs) to reduce the possibility of serious spills and improve the safety record nationwide (see Section 8.3.3.1).

Means are available (see Section 8) for estimating the reduction of the frequency and volume of spills using preventive maintenance programs. Such information allows one to estimate future oil spill trends for a particular pipeline or nationwide.

SECTION 3

RECOMMENDATIONS

Preventive maintenance programs for preventing spills from the line pipe of operational lines are recommended. These programs, along with new and developmental leak detection and inspection methods, should continue to be investigated. Recommended preventive maintenance programs presented in Section 8 are primarily intended to aid operating companies in evaluating the need and in the actual development of a spill prevention and control program for their own operational line. In addition, this information can aid various local and Federal agencies in evaluating problem areas and available means of minimizing the problem.

Since there are numerous variations between lines and wide ranges in the oil spill risk, it is beyond the scope of this study to recommend programs for particular lines. Hence, recommendations are generalized and do not include specific details for implementing methods for particular lines. The preventive maintenance programs include scheduled inspections and/or in situ leak detection (some functioning continuously) that could be effectively developed and implemented. The programs, if implemented, are expected to improve significantly the prevention and control of accidental spills of petroleum from operational lines. Nationwide implementation of such programs is expected to decrease, substantially, the total quantity of petroleum lost, the number of spill incidents and the number of major spill incidents. Estimates of these reductions are presented in Section 8.

The recommended approach for development of a spill preventing program for an individual or group of lines was based on the following steps:

- Estimate the risk that oil will escape from a line (see Section 6.3.4.1).
- Identify locations of a line where a spill may create special, serious problems (see Sections 6.3.3.4 and 6.3.4.2) such as the possible damage to the external environment or cost of spill cleanup.
- Estimate the level of corrective action to reduce the spill risk to an acceptable level.
- Identify the various options of spill prevention that are available to achieve the necessary reductions in the spill risk (see Sections 8.3.2 and 7.1.2).

- Select the optimum methods based on the cost effectiveness and other considerations of the various suitable options.

A recommended general schedule for the reduction of the frequency and volume of spills is provided in Section 8.3.2. The general schedule produces confidence that an individual line or group of lines will have no more than (X) barrels spilled and (X) number of incidents per year. The recommended approach is to first estimate the risk that oil will escape from the line (see Section 6.3.4.1). Then select one of the following specific preventive maintenance schedules:

- Reduction of frequency of spills - Table 80
- Reduction of volume of spills - Table 81
- Reduction of frequency and volume of spills - Table 82.

Using the approach and indicated schedule, selected spillage reductions of greater than 25 percent, 50 percent and 75 percent may be achieved.

Preventive maintenance programs with specific schedules and applications were recommended as follows:

(1) Most U.S. Lines:

- Visual inspections of the line by air or ground patrol--weekly
- One-call system (Reference 12)
- Survey by inspection pig (magnetic flux type or other comparable device) every 4 years

or

- Hydrostatic tests

  - yearly or
  - after indication of spill.

(2) Underwater lines:

- Visual inspections of the line by air or ground patrol--weekly
- Depth of cover inspection by sonar or other comparable device--every 2 years
- Hydrocarbon probe (towfish or similar device) inspection--yearly

EPA Form 2350-6 (4-80)
TYPING GUIDE SHEET

- Survey by inspection pig (magnetic flux type or other comparable device)--every 2 years

or

- Hydrostatic test--yearly.

(See also recommended developmental and new methods.)

(3) Large-diameter lines:

- Visual inspection by air or ground patrol--weekly
- One-call system (reference 12)
- Survey by inspection pig (magnetic flux type or other comparable device)--every 4 years
- Volume comparison, flow rate comparison, and pressure deviation

or

- Mathematical modeling.

(See also recommended developmental and new methods, Section 8.4.)

(4) Old lines:

- Visual inspections by air or ground patrol--weekly
- One-call system (reference 12)
- Survey by inspection pig (magnetic flux type or comparable device)--every 3 years

or

- Hydrostatic tests

  - yearly or
  - after indication of spill.

(5) Lines with two or more reportable spill incidents within 1 year:[a]

- Visual inspection by air or ground patrol--weekly
- One-call system (reference 12)

---

[a] Recommended to be in effect for approximately 3 years after spill incidents are reduced to a normal rate.

- Survey by inspection pig (magnetic flux type or comparable device)--every year
- Hydrostatic tests--yearly.

This schedule should be in effect until approximately three years after spill incidents are reduced to a normal rate.

Recommended developmental and new inspection and leak detection methods include:

- Mathematical modeling
- Passive acoustic array
    - retrofit (prevent and/or detect damage from outside forces)
    - new lines (prevent damage and detect failures).

TYPING GUIDE SHEET

SECTION 4

PETROLEUM TRANSPORT - SYSTEMS, MEASUREMENT, CHANGES AND LOSSES

The extent and nature of petroleum losses from the petroleum transportation systems are studied in this section to provide an overall perspective of the problem of accidental spills from petroleum transportation systems. Estimates are made of the total quantity of petroleum lost and the amount attributable to each major loss mechanism. Emphasis is directed to the problem of spills from the transmission line (line pipe). This section also provides basic information that is used in the detailed analysis of the oil spill risks (see Section 6) and the capabilities or methods to reduce the risk (see Section 7).

The problems and limitations that affect the accuracy of the estimates of the total petroleum losses or the losses from specific mechanisms are discussed. These include:

- Variety of complex petroleum transportation systems in use
- Poor and sometimes inadequate information on petroleum systems and loss statistics
- Numerous sources of errors that are possible in
  - measurement of losses
  - petroleum accounting and loss reporting to U.S. Government agencies
  - compilation of petroleum and losses by U.S. Government agencies
  - operational and accounting practices of each individual company
  - other.

Important areas necessary in determining losses are presented and used in determining actual losses. Specific areas include:

- Petroleum system description
- Loss mechanisms
- Measurement
- Fluid changes

- Instrumentation system accuracies
- Loss statistics.

Each area is discussed in separate subsections.

In order to have an overall understanding of the petroleum transportation system, the various means of petroleum transport are reviewed in Section 4.1. Distribution and storage are discussed and the transportation modes compared. Petroleum pipeline systems are described and detailed information is presented on mileage, diameter, age, type of pipeline, and type and volume of oil transported. A pipeline grouping system is also selected.

Commonly used means of measuring and estimating the losses are examined in detail for the petroleum pipeline system in Section 4.2. Significant loss mechanisms, i.e., evaporation, leaks, and admixture shrinkage, and false indications of losses that create either a bias or uncertainty in the loss measurement are identified and briefly discussed.

The ability to accurately measure petroleum (including losses) is discussed in detail in Section 4.3. Meter errors, calibration errors, variable conditions that affect meter performance, inaccurate correction factors, accounting errors, human errors and bias and false indication of errors are considered.

Changes in fluid between receipt and delivery are discussed in Section 4.4. Fluid temperatures, water settling, admixture shrinkage and other factors are considered.

Total system measurement errors are discussed in Section 4.5. Combined errors of typical leak detection equipment and typical line fluctuations (variations of pressure, temperature, etc.) are considered. System errors are converted to barrels of oil that can go undetected for a typical instrumentation system and typical line variations.

An analysis of petroleum loss statistics is carried out in Section 4.6. This was done primarily to estimate total losses for the petroleum pipeline systems and for each loss mechanism. The data analyzed were obtained primarily from U.S. Government published statistics. However, statistics from foreign countries, reports from government agencies and programs, statistics from major oil companies, and loss analyses of reported losses by Science Applications, Inc. (SAI) and others are used also. An in-depth analysis of the oil spill statistics is carried out. Particular emphasis is placed upon spill statistics of pipeline systems. This information is examined in detail for both the overall pipeline system and the most critical component, i.e., line pipe. Information such as the number, frequency, volume and severity of spills is examined in depth to determine key factors, e.g., line pipe age and geometry, relating to the oil spill risk of pipeline systems.

Estimates of total petroleum losses and total losses of specific loss mechanisms for U.S. pipeline transportation systems are given in Section 4.7. This evaluation is made based on the data and information presented in the previous subsections.

4.1 PETROLEUM TRANSPORTATION SYSTEM DESCRIPTION

The petroleum transportation system in the U.S. distributes and stores petroleum by various means between the supply and retail outlet to the refineries and markets. Transfer is carried out primarily by pipelines, tankers, barges, railroad tank cars and tank trucks. A simplified version of the petroleum transportation system with the main distribution and storage components is shown in Figure 1. A transportation model is given in Figure 2. Petroleum supply obtained from production operations is given in Figure 3.

Quantitative information on the major modes of petroleum transfer, including the type and volume of oil transported, and a pipeline grouping system is presented in the subsections that follow. Detailed information is presented for the petroleum pipeline system because it is the major means of transporting petroleum and responsible for most of the losses in the petroleum transportation system.

4.1.1 Percentage of Petroleum Moved by Transportation Modes

Pipeline systems currently account for more than half of the petroleum transported in the U.S. and this percentage has been increasing over the past forty years. Data on the percentage of crude and gasoline moved by various modes in 1975 are given in Table 1.

TABLE 1. PERCENTAGE OF CRUDE AND GASOLINE MOVED IN 1975[a], BY METHOD OF TRANSPORTATION

Method[b]	Crude	Gasoline
Pipeline	77.4	42
Coastal tanker	10.75	18
Barge	10.75	18
Truck	0.55	21
Railroad	0.55	0.35

[a] Reference 2

[b] Trip length varies for the particular transportation mode. Typical trip lengths (4) for these modes are the following: pipeline, 300 miles; tankers, 50 miles; barge, 3000 miles (round trip); truck, 500 miles, trains, 500 miles.

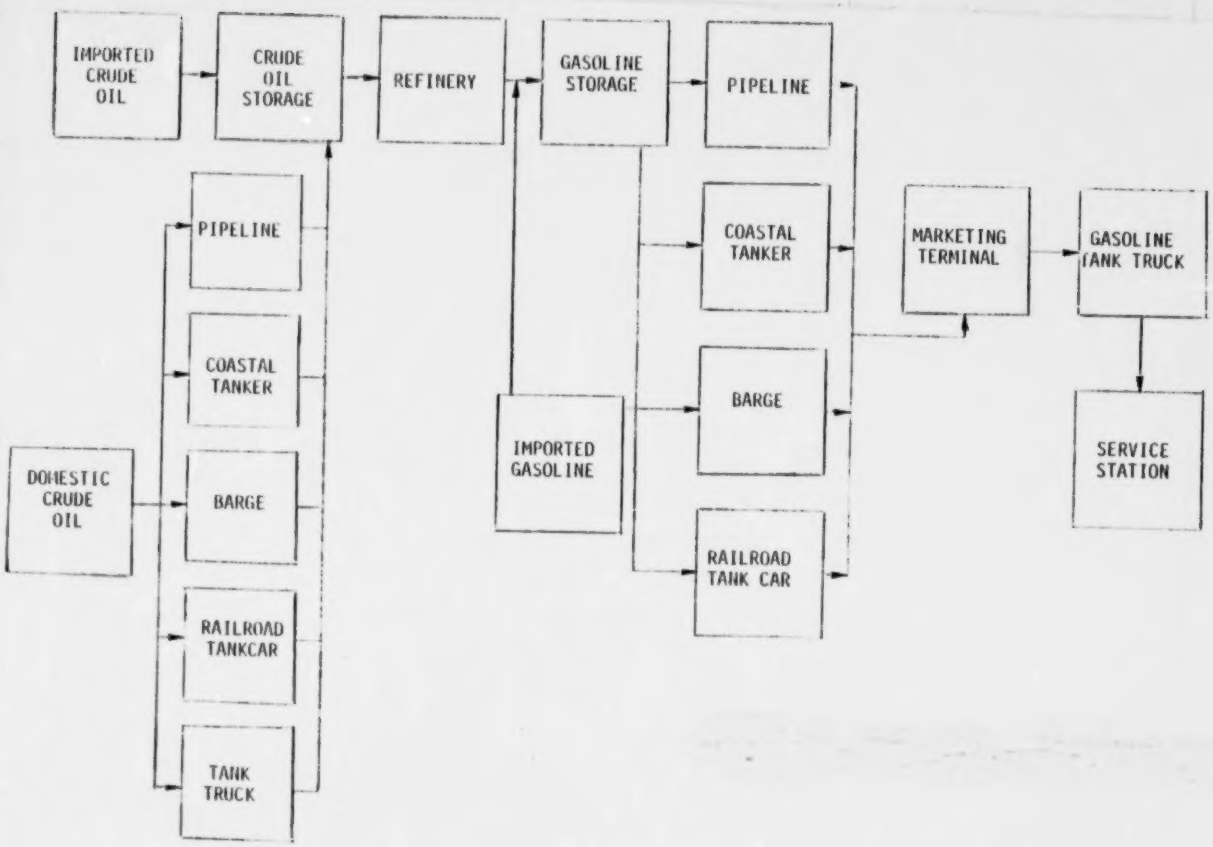

IMPORTED CRUDE OIL
CRUDE OIL STORAGE
REFINERY
GASOLINE STORAGE
PIPELINE
COASTAL TANKER
BARGE
RAILROAD TANK CAR
MARKETING TERMINAL
GASOLINE TANK TRUCK
SERVICE STATION
IMPORTED GASOLINE
DOMESTIC CRUDE OIL
PIPELINE
COASTAL TANKER
BARGE
RAILROAD TANKCAR
TANK TRUCK

Figure 1. Petroleum transportation system. (Source: Reference 2.)

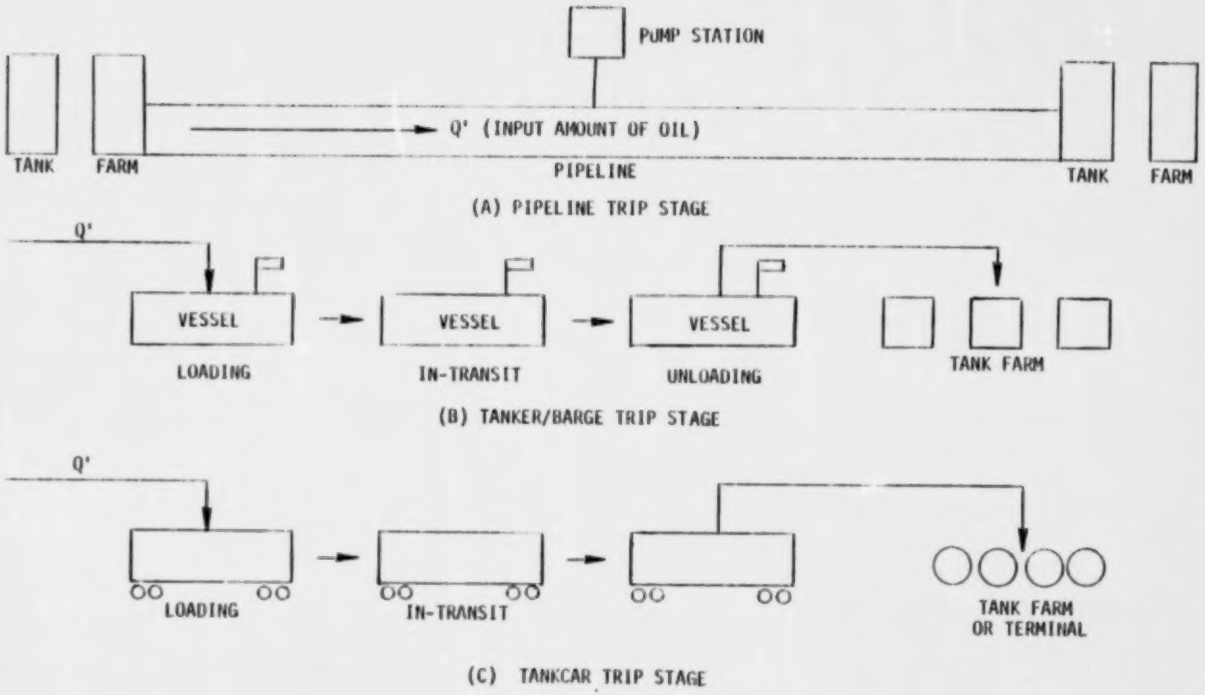

PUMP STATION
TANK
FARM
Q' (INPUT AMOUNT OF OIL)
PIPELINE
TANK
FARM
(A) PIPELINE TRIP STAGE
Q'
VESSEL
VESSEL
VESSEL
LOADING
IN-TRANSIT
UNLOADING
TANK FARM
(B) TANKER/BARGE TRIP STAGE
Q'
LOADING
IN-TRANSIT
TANK FARM
OR TERMINAL
(C) TANKCAR TRIP STAGE

Figure 2. Petroleum transportation model. (Source: Reference 2.)

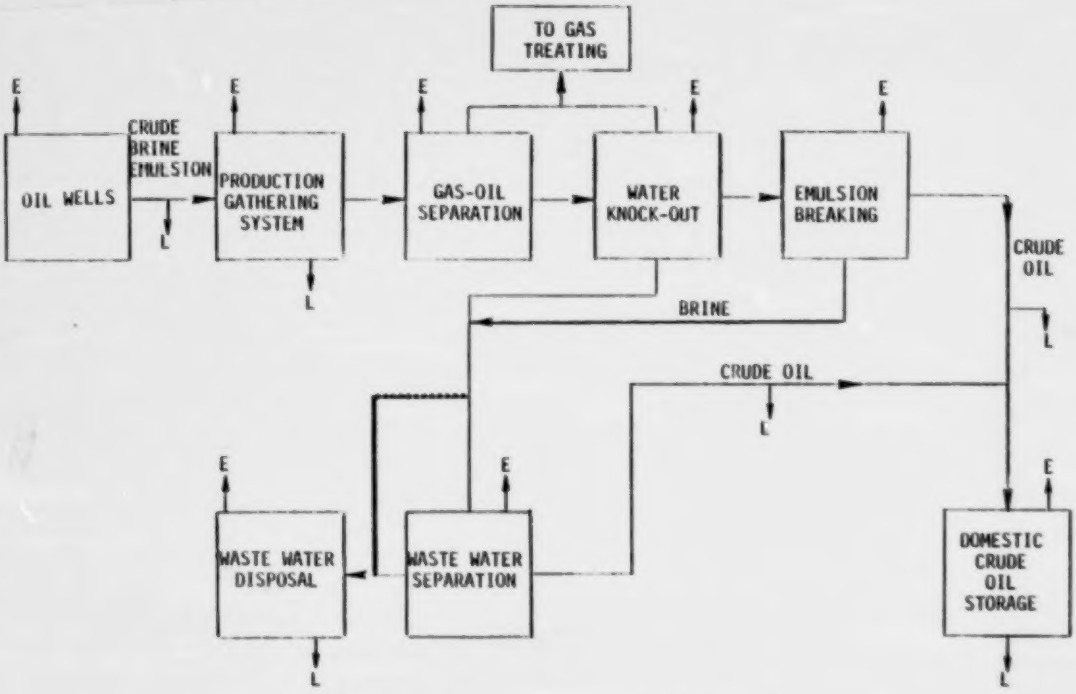

TO GAS TREATING
E
L
CRUDE BRINE EMULSION
OIL WELLS
PRODUCTION GATHERING SYSTEM
GAS-OIL SEPARATION
WATER KNOCK-OUT
EMULSION BREAKING
CRUDE OIL
BRINE
CRUDE OIL
WASTE WATER DISPOSAL
WASTE WATER SEPARATION
DOMESTIC CRUDE OIL STORAGE

Figure 3. Flowsheet of petroleum production operations.

Currently, over 77 percent of the crude and 42 percent of the gasoline are transported by pipeline systems. Table 2 shows similar results for crude and refined products and reveals an increasing trend in the percentage transported for the years between 1938 and 1974.

4.1.2 Type and Volume of Petroleum Supplied and Transported

Annual statistics on the type and volume of petroleum supplied and transported in the U.S. are compiled by the Bureau of Mines (BOM)[3]. Table 3 shows these statistics for the volume of crude and gasoline produced and imported for the years 1972 through 1977. During this 6-year period, the total volume increased at an annual rate of about 4 percent from 6.6 billion to 8.0 billion barrels per year. United States production of crude both onland and offshore (Table 4) decreased an average of about 2 and 4 percent a year, respectively. Data on foreign and domestic crude and natural gas liquids transported by pipelines to refinery input and petroleum products turned into pipelines for the 5-year period between 1972 and 1976 are given in Table 5. During this period, total liquids transported increased an average of about 2 percent a year to 8.9 billion barrels.

Annual statistics on the volume and type of petroleum transported interstate are compiled by the Interstate Commerce Commission (ICC)[6]. Total volume received into the interstate system (Table 6) increased from 6.2 billion barrels in 1966 to 9.8 billion barrels in 1976. This represents an average volume increase of about 5 percent a year over this 11-year period. The number of barrel-miles in trunk line movement also increased at a similar rate.

4.1.3 Pipeline Transportation System

Petroleum pipeline transportation systems in the United States consist of many individual systems of diverse design, dimensions, construction, materials, age, operation and maintenance. However, most systems transporting liquids through pipelines fall under the jurisdiction of Federal regulation (Title 49- Part 195)[7] and must meet the same standards in design, construction, testing, operation and maintenance, and accident reporting. These regulations are given in Appendix A.

Typical pipeline systems are shown in the simplified diagram in Figure 2(A) and the more detailed diagram in Figure 4. In this study, pipeline systems (Table 7) are separated into two major areas (onshore and offshore) with four major components (production, pumping, pipeline and terminals).

Petroleum pipeline systems are comprised of three main components: pipelines, storage tanks and pumping stations. Crude gathering lines are the means through which crude oil is first gathered from production wells. Crude is operated on, temporarily stored and then transported to refineries by trunklines. Product trunklines then distribute products from the refineries to markets and marine terminals. Storage tanks provide short-term

TABLE 2. PERCENTAGE OF CRUDE PETROLEUM AND PETROLEUM PRODUCTS MOVED BY METHOD OF TRANSPORTATION, 1938-1974[a]

	Crude				Product			
Year	Pipeline	Water Carriers	Motor Carriers	Railroad	Pipelines	Water Carriers	Motor Carriers	Railroad
1938	71.01	25.58	1.17	2.24	6.35	52.65	10.59	30.41
1948	68.48	23.26	3.86	4.40	11.36	44.70	29.85	14.09
1958	76.35	16.90	6.45	0.30	20.48	37.51	36.76	5.25
1968	74.08	18.62	7.11	0.19	30.41	25.69	41.35	2.55
1970	74.30	18.90	6.65	0.15	31.12	26.75	39.72	2.41
1972	75.75	16.10	7.92	0.23	32.39	26.92	38.55	2.14
1973	76.89	14.13	8.68	0.30	32.74	25.78	39.31	2.17
1974	74.81	13.47	11.29	0.43	33.54	25.84	38.48	2.17

[a] Source: Reference 5.

TABLE 3. VOLUME OF OIL PRODUCED AND IMPORTED, 1972-1977
(THOUSANDS OF BARRELS)

Year	Crude			Gasoline			Crude and Gasoline		
	Produced	Imported	Total	Produced	Imported	Total	Produced	Imported	Total
1972	3,455,368	811,135	4,266,503	2,319,950	24,787	2,344,737	5,775,318	835,922	6,611,240
1973	3,360,903	1,183,996	4,544,899	2,401,860	48,759	2,450,619	5,762,763	1,232,755	6,995,518
1974	3,202,585	1,269,155	4,471,740	2,337,467	74,402	2,411,869	5,540,052	1,343,557	6,883,609
1975	3,056,779	1,498,181	4,554,960	2,379,919	67,249	2,447,168	5,436,698	1,565,430	7,002,128
1976	2,976,180	1,935,012	4,911,192	2,516,989	47,774	2,564,763	5,493,169	1,982,786	7,475,955
1977	2,985,360	2,397,468	5,382,828	2,581,971	78,434	2,660,405	5,567,331	2,475,902	8,043,233

TABLE 4. OFFSHORE PRODUCTION OF CRUDE PETROLEUM
(THOUSANDS OF BARRELS)

State	1973	1974	1975	1976	1977
Alaska	62,132	60,308	60,358	54,512	50,043
California					
Total	89,261	83,918	79,671	70,587	60,471
Federal	18,781	16,779	15,435	13,975	12,282
State	70,480	67,134	64,236	56,612	48,189
Louisiana					
Total	436,875	398,329	356,458	335,849	316,366
Federal	381,607	351,825	316,480	298,378	282,552
State	55,268	46,825	39,978	37,471	33,814
Texas					
Total	1,419	1,081	779	1,522	2,891
Federal	738	504	426	812	382
State	681	577	353	710	2,509
U.S. Total	589,687	543,636	497,266	462,470	429,771

TABLE 5. VOLUME OF PETROLEUM TRANSPORTED BY PIPELINES IN THE UNITED STATES (THOUSANDS OF BARRELS)

	Refinery Input Receipts	1972	1973	1974	1975	1976
A.	Crude domestic					
	Interstate					
	Pipeline		1,796,892	1,691,458	1,641,005	1,622,620
	Tankers and barges		148,862	130,410	134,857	123,824
	Interstate					
	Pipeline		1,108,101	1,061,441	1,021,514	1,102,118
	Tankers and barges		249,819	211,530	170,168	146,825
	Total - domestic crude		3,303,674	3,095,839	2,967,544	2,995,387
B.	Crude foreign					
	Pipelines		408,740	370,654	397,518	443,026
	Tankers and barges		775,331	896,142	1,100,973	1,487,350
	Total - foreign crude		1,184,071	1,266,796	1,498,491	1,930,763
	Total - domestic and foreign crude (A,B)		4,487,745	4,362,635	4,466,035	4,925,763
C.	Natural gas liquids	302,445	297,482	272,416	259,319	265,451
	Total - all refinery inputs (A,B,C)		4,785,227	4,635,051	4,725,354	5,191,214
D.	Petroleum products turned into pipelines					
	Gasoline	1,636,213	1,759,322	1,773,951	1,822,830	2,003,207
	Jet fuel	228,476	249,621	248,315	259,578	323,233
	Kerosene	47,499	46,883	35,941	30,864	30,394
	Distilled fuel oil	656,798	727,019	701,798	667,058	745,335
	Natural gas liquids	438,000	438,000	467,286	504,714	567,070
	Total petroleum products	3,006,986	3,220,845	3,227,285	3,285,044	3,669,244
	TOTAL A,B,C,D		8,006,072	7,862,336	8,010,398	8,860,458

TABLE 6. VOLUME AND TYPE OF OIL TRANSPORTED BY INTERSTATE PIPELINE SYSTEMS

Oil transported statistics	1976	1975	1974	1970	1969	1968	1967	1966
No. of barrels received into system:								
From connecting carriers:								
Crude oil	2,611,306,000	2,194,757,000	2,185,749,000	1,729,963,878	1,637,986,854	1,530,981,236	1,456,006,801	1,388,396,020
Products	511,521,000	504,782,000	526,239,000	415,840,204	395,999,695	351,802,367	305,236,793	262,979,877
Total	3,122,827,000	2,699,539,000	2,711,988,000	2,145,804,082	2,033,986,549	1,882,783,603	1,761,243,594	1,651,375,897
Originated:								
Crude oil	3,434,362,000	3,492,617,000	3,575,464,000	3,568,346,998	3,404,988,846	3,203,481,568	3,017,250,927	2,826,374,622
Products	3,229,841,000	3,166,659,000	3,072,546,000	2,449,380,365	2,316,317,430	2,203,169,701	2,035,245,612	1,773,954,368
Total	6,664,203,000	6,659,275,000	6,648,010,000	6,017,727,363	5,721,306,276	5,406,651,269	5,052,496,539	4,600,328,990
Total received into system	9,787,030,000	9,358,814,000	9,359,998,000	8,163,531,445	7,755,292,825	7,289,434,872	6,813,740,133	6,251,704,887
No. of barrels delivered out of system:								
To connecting carriers:								
Crude oil	2,256,131,000	2,125,955,000	2,055,769,000	1,767,068,133	1,696,310,931	1,528,033,969	1,423,072,341	1,369,843,916
Products	719,675,000	691,360,000	692,200,000	552,544,037	546,233,948	519,796,144	467,072,509	400,508,661
Total	2,975,806,000	2,817,315,000	2,747,970,000	2,319,612,170	2,242,544,879	2,047,830,113	1,890,144,850	1,770,352,577
Terminated:								
Crude oil	3,764,689,000	3,548,507,000	3,679,549,000	3,520,580,985	3,335,595,359	3,188,167,552	3,046,870,063	2,833,258,057
Products	3,016,608,000	2,974,788,000	2,905,822,000	2,306,491,599	2,163,674,983	2,032,761,561	1,863,409,038	1,634,581,587
Total	6,781,297,000	6,523,295,000	6,585,371,000	5,827,072,584	5,499,270,342	5,220,929,113	4,910,279,101	4,467,839,644
Total delivered out of system	9,757,103,000	9,340,610,000	9,333,340,000	8,146,684,754	7,741,815,221	7,268,759,226	6,800,423,951	6,238,192,221
No. of barrels having truck line movement:								
Crude oil	5,824,141,000	5,369,293,000	5,390,999,000	4,756,244,120	4,445,921,966	4,273,298,625	3,886,370,613	3,661,172,872
Products	3,813,233,000	3,645,461,000	3,588,808,000	2,863,735,391	2,718,870,361	2,559,522,918	2,338,581,680	2,049,934,224
No. of barrel-miles (truck lines):								
Crude oil	1,609,173,784	1,545,061,092	1,625,436,501	1,428,362,484	1,321,711,176	1,270,465,366	1,207,321,010	1,181,152,599
Products	1,307,449,941	1,333,874,961	1,239,411,795	1,021,484,502	995,029,558	951,655,430	925,121,262	719,728,561

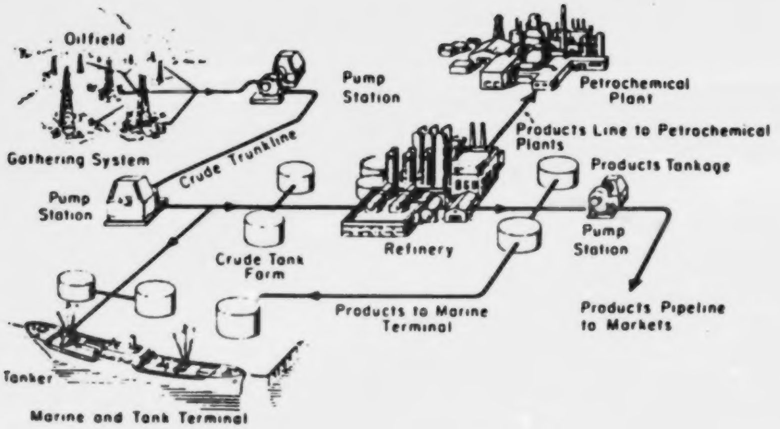

Oilfield
Pump Station
Petrochemical Plant
Products Line to Petrochemical Plants
Gathering System
Crude Trunkline
Products Tankage
Pump Station
Refinery
Pump Station
Crude Tank Farm
Products to Marine Terminal
Products Pipeline to Markets
Tanker
Marine and Tank Terminal

Figure 4. A pipeline system composed of gathering, trunk and distribution lines. (Source: Reference 8.)

TABLE 7. PIPELINE TRANSPORTATION SYSTEM AND ASSOCIATED SUBSYSTEMS

Onshore

1. Production

- Wells
  - Piping
  - Valves
  - Pumps
- Production gathering system
  - Piping
- Operations
  - Emission breaking
  - Water knockout
  - Gas-oil separation
  - Waste water separation
  - Waste water disposal
    - Piping
    - Gaskets
    - Valves
    - Flanges
  - Storage tanks
    - Piping
    - Seals
    - Gaskets
    - Flanges
    - Valves

2. Booster Pumping Station

- Pump section
  - Piping
  - Pump
  - Block valves
  - Strainer
  - Check valves
- Tankage
- Launcher
  - Valves
  - Container
  - Drain valve
  - Gasket

3. Pipeline (Crude gathering, crude and product trunklines)

- Underground pipeline
  - Pipe
  - Seals
  - Gaskets
  - Flanges
  - Valves
- Aboveground pipeline
  - Pipe
  - Seals
  - Gaskets
  - Flanges
  - Valves

4. Storage Terminals

- Pipe and manifold aboveground
  - Seals
  - Gaskets
  - Flanges
  - Valves
- Pipe and manifold underground
- Pig traps
- Strainer
- Custodial metering
- Meter prover
- Storage tanks
  - Piping
  - Seals
  - Gaskets
  - Flanges
  - Valves
- Drainage control system
  - Retaining dike
  - Pipe outlet
  - Gate valve

Offshore

1. Production

- Wells
  - Piping
  - Valves
  - Pumps
- Storage tanks
  - Piping
  - Seals
  - Gaskets
  - Flanges
  - Valves
- Production gathering system
  - Piping
- Operations
  - Emission breaking
  - Water knockout
  - Waste water separation
  - Waste water disposal
    - Piping
    - Gaskets
    - Flanges
    - Seals

2. Pumping Platform

- Platform support
- Waste disposal system
  - Piping
  - Valve
  - Sea sump
  - M.O. tank pump
  - Air eliminator drain pipe valve
  - Reclaimed oil tank valve
  - Oil water sump
- Upstream from pumps
  - Sampler
  - Strainer
  - Air eliminator
- Pump section
  - Piping
  - Pump-valve
    - MOV
    - Seals
  - Flanges
- Downstream from pumps
  - Metering custodian
    - Control valve
    - Straightener
    - Flow meter
    - Flange
  - Meter prover
  - Launcher-valve
    - Container
    - Drain valve
    - Gaskets
  - Flanges
  - Piping
  - Brackets

3. Underwater Pipeline (Crude gathering, crude and product trunklines)

- Underwater pipeline
- Piping
- Seals
- Gaskets
- Flanges
- Valves

4. Marine Terminal

- Pipe and manifold aboveground
  - Seals
  - Gaskets
  - Flanges
  - Valves
- Pipe and manifold underground
- Pig traps
- Strainer
- Custodial metering
- Meter prover
- Storage tanks
  - Pipes
  - Seals
  - Gaskets
  - Flanges
  - Valves
- Drainage control system
  - Retaining dike
  - Pipe outlet
  - Gate valve

storage for receiving, measuring, sorting and routing. Pumping stations normally are installed every 25 to 150 miles along a line and furnish the energy to transport the petroleum at proper pressures.

A variety of petroleum pipeline systems exist and significant changes and trends in construction have occurred in recent years. In order to account for these, pertinent pipeline system information such as pipeline dimension (diameter, length), age, type, volume and type of oil transported, storage, etc., must be considered. Also, a suitable pipeline grouping system is necessary for effective utilization of pipeline system data. This information is presented in the subsections that follow.

4.1.3.1 Pipeline - Construction, Mileage, Diameter, Type, Fluid, Age--

The petroleum pipeline system has undergone numerous changes and substantial growth (Figures 5 and 6) over the past forty years. Rapid acceleration of pipeline construction and pipeline flow to the East Coast occurred during the war years in the mid-1940's. Shortly after the war, many crude petroleum pipelines were taken out of service, or converted to gas or product pipelines. Since the 1950's larger diameter, long distance trunklines have been constructed.

Petroleum pipelines are normally made of steel pipe with butt welded joints and are as large as 54 inches in diameter. These pipelines are usually protected from external corrosion by coatings or cathodic protection and from internal corrosion by injection of corrosion inhibitors and chemicals. Petroleum pipelines are normally buried underground or underwater as protection from external damage. Modern pipelines are made with heavy wall steel pipe and high tensile and bursting strength. Only ten years ago, however, standard weight steel pipe with yields to only 50,000 psi was normally used.

Data on total pipeline mileage (Table 8) in service by category are compiled by BOM[9,10,11] and by the ICC[6] for interstate pipeline mileage. Currently there are about 227,000 miles of pipelines and 174,000 miles of these are interstate. In the past nine years, pipeline mileage has increased at a rate of about 1 percent a year.

Mileage by pipeline diameter is given in Tables 9 and 10. Most of the pipelines are 12 inches or less in diameter. These sizes currently account for 191,593 miles or 84 percent of the total pipeline mileage; mileage has increased only slightly, at a rate of about 0.4 percent per year, from the 183,519 miles that existed in 1968. Mileage of large diameter pipelines, however, has increased substantially in the past few years. For example, in 1968 there were 3,312 miles of pipeline larger than 24 inches in diameter and in 1977 there were about 8,268 miles. This is an increase of about 150 percent over that 10-year period. The relationship between pipe diameter, length and volume contained inside is given in Table 11. Note that volume increased by the diameter squared. Thus, significant increases in larger diameter pipeline mileages result in huge increases in pipeline capacity and throughput.

BEGIN FIRST LINE OF TEXT HERE
CENTER OF PAGE
TOP OF IMAGE AREA
DROPPED HEAD BEGIN SECTIONS HERE

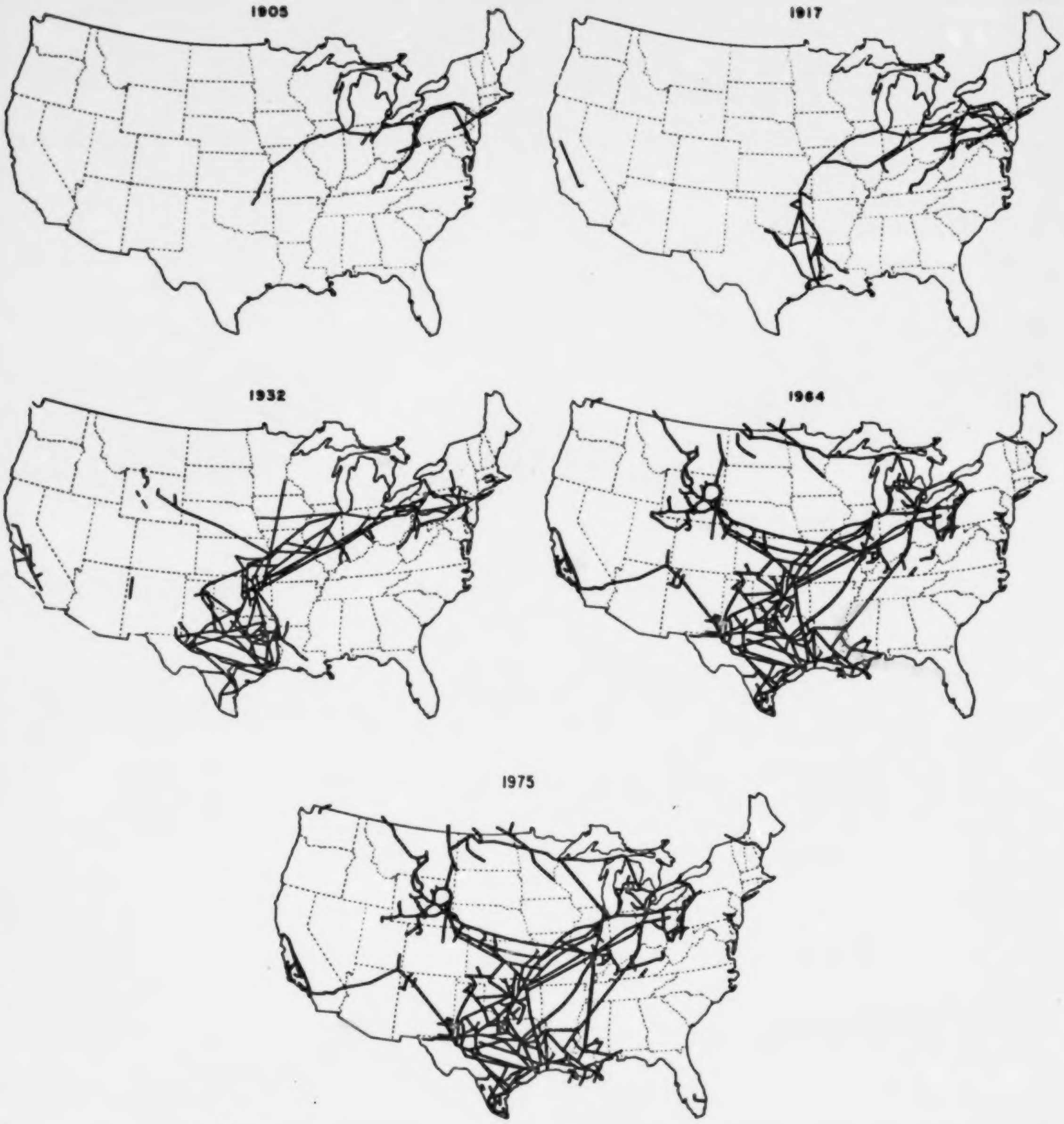

1905
1917
1932
1964
1975

Figure 5. Growth of crude oil pipelines in the United States. (Source: Reference 8.)

TYPING GUIDE SHEET

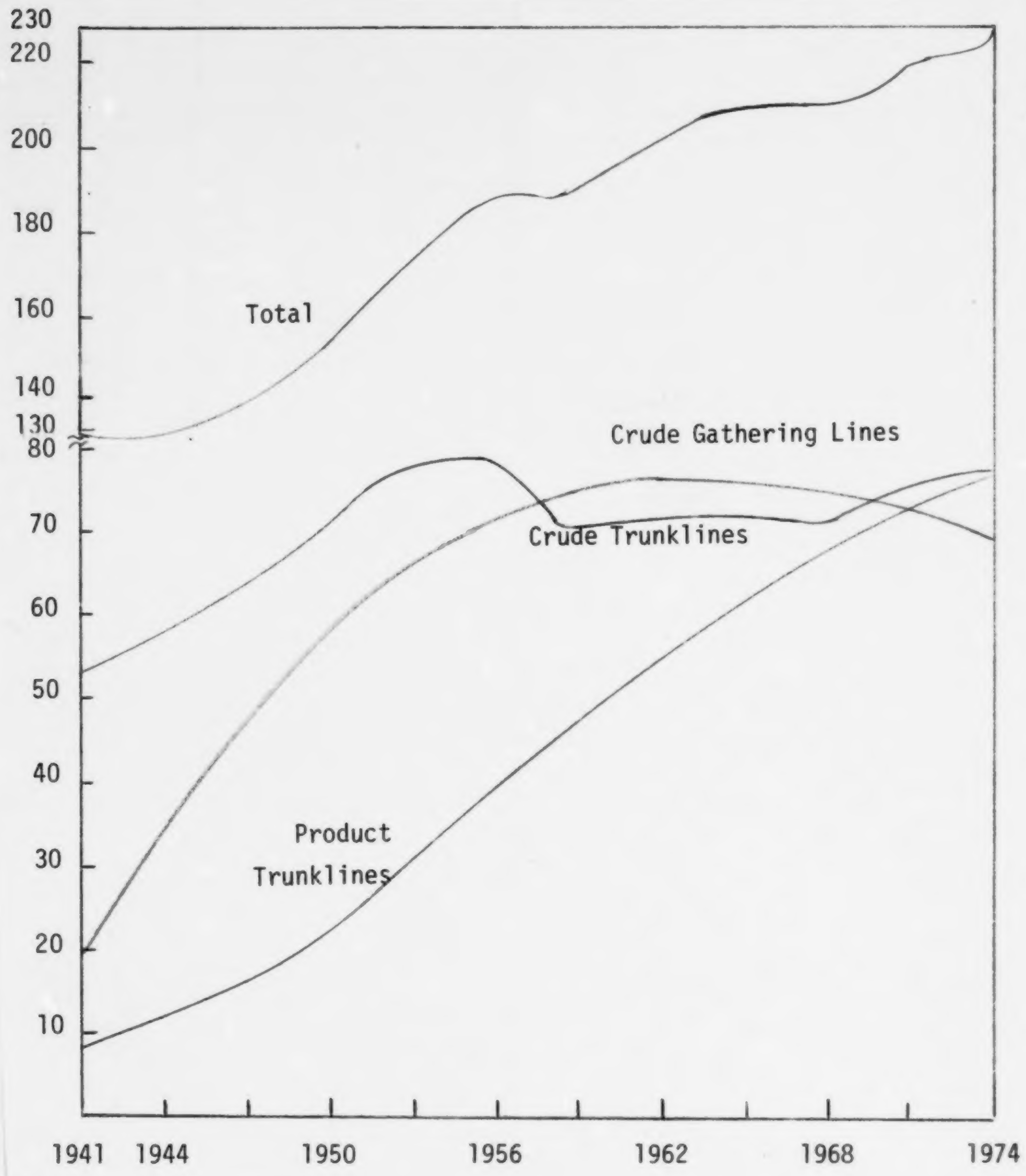


Figure 6. Mileage of petroleum pipelines in the United States.

TYPING GUIDE SHEET

TABLE 8. PIPELINE MILEAGE IN THE UNITED STATES - TOTAL AND INTERSTATE

Year	Trunklines Crude	Trunklines Products	Trunklines Total	Gathering Lines	Total
		Total in the United States			
1926	44,470	a	44,470	45,700	90,170
1931	58,020	a	58,020	53,640	111,660
1936	57,820	a	57,820	52,760	110,580
1941	65,180	9,001	74,181	53,170	127,351
1950	71,373	20,881	92,254	60,560	152,814
1953	75,228	27,236	102,464	68,040	170,504
1956	78,594	36,420	115,014	73,526	188,540
1959	70,317	44,483	114,800	75,182	189,982
1962	70,355	53,200	123,555	76,988	200,543
1965	72,383	61,443	133,826	77,041	210,867
1968	70,825	64,529	135,354	74,124	209,478
1971	75,143[b]	72,396[b]	147,539	71,132	218,671[b]
1974	76,250	78,038	154,288	69,247[b]	223,535[b]
1977	77,972	81,296	159,268	67,798	227,066
		Total Interstate			
1976	58,544	67,913	126,457	39,235	174,072

[a] Included in crude lines.

[b] Revised.

TABLE 9. MILEAGE OF PETROLEUM PIPELINES BY DIAMETER IN THE UNITED STATES, JANUARY 1, 1971 AND JANUARY 1, 1974[a]

	Tankers				Gathering Lines		Total	
	Crude		Products					
Size (Inches)	Jan 1, 1977	Jan 1, 1974	Jan 1, 1977	Jan 1, 1974	Jan 1, 1977	Jan 1, 1974	Jan 1, 1977	Jan 1, 1974
2	84	100	125	156[b]	12,575	13,547	12,784	13,803
3	468	479	630	688[b]	10,252	11,020	11,350	12,187[b]
4[c]	3,760	3,344	2,895	2,870[b]	27,382	27,687	33,537	33,901[b]
6[d]	9,518	9,668	17,786[b]	16,786[b]	10,425	10,210[b]	37,508	36,664[b]
8[e]	19,303	20,424	27,193	27,329[b]	5,023	5,139[b]	51,519	52,892[b]
10[f]	11,358	11,040	11,958	10,612[b]	1,075	940	24,391	22,592[b]
12	10,156	10,183	9,394	8,703[b]	954	626	20,504	19,512[b]
14	589	598	2,817	2,786	39	18	3,445	3,402
16	5,975	5,668	2,077	1,954[b]	49	42	8,101	7,664[b]
18	2,059	2,091	1,202	1,177	1	1	3,262	3,269
20	5,251	4,972	1,238	1,072[b]	15	9	6,504	6,053[b]
22	3,059	2,664	9	9	1	1	3,069	2,674
24	2,256	1,483	566	543	2	3	2,824	2,029
26	1,069	1,034	287	287	5	4	1,361	1,325
28	-	-	597	546	-	-	597	546
30	2,006	960	520	480	-	-	2,526	1,440
32	-	-	288	288	-	-	288	288
34[g]	785	789	233	233	-	-	1,018	1,022
36	134	5	1,519	1,519	-	-	1,653	1,524
40	527	637	183	-	-	-	710	637
42	4	3	-	-	-	-	4	3
48	111	108	-	-	-	-	111	108
Total	77,972	76,250	81,296	78,038[b]	67,798	69,247[b]	227,066	223,535[b]

[a] Source: Reference 10.

[b] Revised.

[c] Includes a small amount of 5-inch pipe in trunklines.

[d] Includes a small amount of 7-inch pipe in trunklines.

[e] Includes a small amount of 9-inch pipe in trunklines.

[f] Includes a small amount of 11-inch pipe in trunklines.

[g] Includes a small amount of 35-inch pipe in trunklines.

TABLE 10. MILEAGE OF PETROLEUM PIPELINES BY DIAMETER IN THE UNITED STATES JANUARY 1, 1971 AND JANUARY 1, 1968[a]

	Trunklines							
	Crude		Products		Gathering Lines		Total	
Size (Inches)	Jan 1, 1971	Jan 1, 1968	Jan 1, 1971	Jan 1, 1968	Jan 1, 1971	Jan 1, 1968	Jan 1, 1971	Jan 1, 1968
2	-	-	-	-	14,463	15,318	14,463	15,318
3[b]	479	269	702	641	11,166	11,980	12,347	12,890
4[c]	3,090	2,075	2,771	2,419	27,769	28,394	33,630	32,888
6[d]	9,435	8,897	16,732	16,002	11,280	12,016	37,447	36,915
8[e]	19,269	19,525	25,634	22,822	4,716	4,842	49,619	47,189
10[f]	11,867	12,198	9,785	8,187	872	846	22,524	21,231
12	10,106	9,288	8,732	7,189	754	611	19,592	17,088
14	571	548	2,441	2,129	27	27	3,039	2,704
16	5,630	5,341	1,603	1,441	65	70	7,298	6,852
18	2,002	1,992	919	937	1	1	2,922	2,930
20	5,040	4,765	907	1,075	15	15	5,962	5,855
22	2,664	2,659	9	9	-	-	2,763	2,668
24	1,504	1,497	131	137	3	3	1,638	1,637
26	1,039	830	217	-	1	1	1,257	831
28	-	-	177	-	-	-	177	-
30	938	645	300	104	-	-	1,238	749
32	-	-	288	288	-	-	288	288
34[g]	792	291	-	-	-	-	792	291
36	2	4	1,058	1,149	-	-	1,060	1,153
40	634	-	-	-	-	-	634	-
42	4	1	-	-	-	-	4	1
Total	75,066	70,825	72,406	64,529	71,132	74,124	218,604	209,478

[a] Source: Reference 11.

[b] Includes a small amount of 2-inch pipe in trunklines.

[c] Includes a small amount of 5-inch pipe in trunklines.

[d] Includes a small amount of 7-inch pipe in trunklines.

[e] Includes a small amount of 9-inch pipe in trunklines.

[f] Includes a small amount of 11-inch pipe in trunklines.

[g] Includes a small amount of 35-inch pipe in trunklines.

TABLE 11. RELATIONSHIP BETWEEN PIPE DIAMETER, LENGTH, AND VOLUME CONTAINED INSIDE[a]

Inside Diameter (in.)	Length[b] required to hold 1000 bbl		Barrels per mile of line	Barrels per km of line
	Miles	Kilometers		
2.067	45.63	73.44	22	14
4.026	12.03	19.36	83	52
6.026	5.37	8.64	186	116
8.071	2.99	4.82	334	208
10.020	1.94	3.13	515	320
12.090	1.33	2.15	750	466
24.000	0.34	0.54	2,954	1,836
28.000	0.25	0.40	4,021	2,499
34.750	0.16	0.26	6,194	3,849
40.00	0.12	0.20	8,207	5,099
46.500	0.09	0.15	11,090	6,891

[a] Source: Reference 12.

[b] $L(mi) = \frac{194.965}{D^2}$ $V(/mi) = 5.129\ D^2$

$L(km) = \frac{313.766}{D^2}$ $V(/km) = 3.187\ D^2$

("D" is in inches.)

Pertinent information on the three types of pipelines, i.e., crude gathering lines, crude trunklines and product or distribution trunklines, are given in Tables 8 through 10. Trunklines currently account for about 57 percent of the total pipeline mileage and 72 percent of the interstate mileage. For the 28-year period between 1950 and 1977 trunkline mileage has increased at a rate of about 2.5 percent a year from 92,254 to 156,268 miles while gathering lines increased at a rate of only about 0.4 percent a year from 60,560 to 67,798 miles. Essentially all gathering lines (over 99 percent) and most trunklines (over 84 percent) are 12 inches or less in diameter.

Statistics on the main types of petroleum fluids transported, crude and product, are also presented in Tables 8 through 10. The current mileage of crude and product trunklines is about the same or 79,972 and 81,296 respectively. However, product trunklines are somewhat smaller in diameter than crude trunklines. For example, over 85 percent of product trunklines and 69 percent of crude trunklines are 12 inches or less in diameter.

Mileage of petroleum pipelines by age is not available from BOM statistics. However, a rough estimate was obtained using statistics from the Office of Pipeline Safety and Operation (OPSO). Mileage figures for various periods were available for natural gas transmission lines and gathering lines. It was assumed that petroleum lines were similar in age to gas lines. Knowing the total petroleum pipeline mileage and assuming the same percentage of petroleum lines as gas lines were installed during the same time periods, an estimated mileage was obtained. Results are shown in Table 12.

Additional information on pipeline mileage, diameter, type, fluid, and age such as pipeline activity, activity by state, etc., are given in Appendix B for the years 1968, 1971, 1974 and 1977.

4.1.3.2 Storage--

Essentially all petroleum in the transfer system is contained in the pipelines and tanks. Operating conditions for containment are illustrated in Figure 7. Statistical information on both storage capacities and inventories is compiled monthly by BOM and periodically by the National Petroleum Council (NPC). A summary of inventories and storage capacities are presented in Tables 13 and 14. Petroleum inventories as reported by BOM include:

- Stocks in crude oil trunklines and their terminals
- Stocks in product trunklines and their terminals
- Crude and product inventories at refineries
- Product stocks in bulk terminals.

Not included are stocks located at marketing outlets and military installations.

TABLE 12. PETROLEUM PIPELINE SYSTEM MILEAGE IN THE U.S., BY YEAR INSTALLED

Miles by Year Installed	1974 Gas Lines Mileage	1974 Gas Lines %	Estimated 1974 Petroleum Line Mileage
Unknown Year	10,130	4	8,941
Prior to 1930	14,101	5	11,176
1930 to 1939	18,084	6	13,412
1940 to 1949	31,906	11	24,588
1950 to 1959	86,533	31	69,295
1960 to 1969	90,964	32	71,531
1970 to now	30,147	11	24,588
Total	282,135		223,535

TYPING GUIDE SHEET

BEGIN FIRST LINE OF TEXT HERE
CENTER OF PAGE
TOP OF IMAGE AREA
DROPPED HEAD: BEGIN SECTIONS HERE

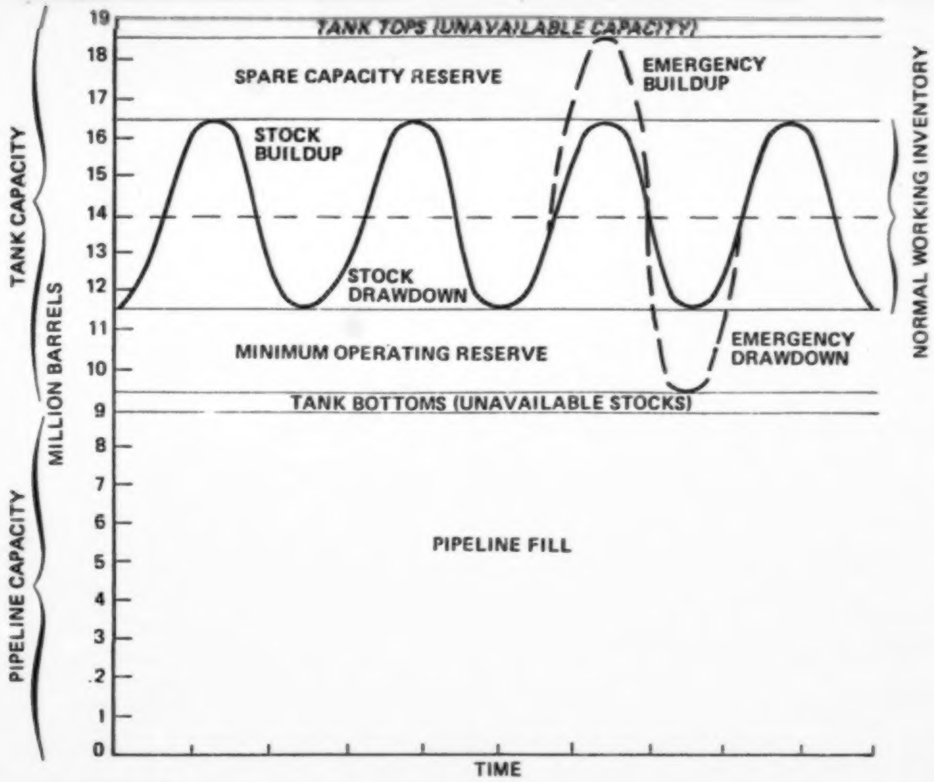


Figure 7. Illustrative operating conditions: Trans-Alaska Pipeline. (Source: Reference 13.)

TYPING GUIDE SHEET

TABLE 13. ANALYSIS OF CRUDE PRODUCTS REPORTED TO NPC[a]

CRUDE OIL INVENTORIES
(Thousands of Barrels)

Item	March 31 1948	June 30 1950	March 31 1952	March 31 1954	March 31 1957	Sept. 30 1962	Sept. 30 1969	Sept. 30 1973
Total Inventories Held by Reporting Companies[b]	213,224	224,948	238,413	243,692	225,516	217,626	240,341	221,859
Unavailable Inventories								
Tank Bottoms & Refineries Operating Requirements[c]	34,067	38,031	39,364	41,423	41,277	41,431	44,701	43,595
Pipeline Fill	30,579	36,618	41,028	44,341	47,036	51,722	60,311	57,141
Other Unavailable	68,279	67,790	70,514	80,884	69,269	66,254	60,977	54,086
Total Unavailable Inventories	132,925	142,439	150,906	166,648	157,582	159,407	165,989	154,822
Unavailable as Percent of Total Reported to NPC	62.3	63.3	63.3	68.4	69.9	73.2	69.1	69.8
Working Stocks and Available Inventories	80,299	82,509	87,507	77,044	67,934	58,219	74,352	67,037

[a] Source: Reference 13.

[b] Excluding producers lease stocks and cargoes in transit from foreign countries.

[c] Contents of tank bottoms, in refinery pipelines and minimum quantity required to assure continuous processing, handling and blending various grades of crude oil.

TABLE 14. ANALYSIS OF CLEAN PRODUCTS REPORTED TO NPC[a]

CLEAN PRODUCTS
(Thousands of Barrels)

Item	March 31 1948	June 30 1950	March 31 1952	March 31 1954	March 31 1957	Sept. 30 1962	Sept. 30 1969	March 31 1973	Sept. 30 1973
Total Inventories Held by Reporting Companies	149,903	180,595	220,283	251,450	294,127	385,840	430,148	358,472	443,254
Unavailable Inventories									
Tank Bottoms	22,262	24,176	26,128	28,865	27,834	32,648	33,783	39,589	39,822
Unfinished at Refineries[b]	8,957	9,403	10,739	7,234	11,520	–[b]	–[b]	–[b]	–[b]
Refinery Lines & Operating Equipment	1,524	1,641	1,768	1,772	1,802	7,190	929	889	914
One-Half Average Size Water Cargo Receipt	9,993	10,077	13,083	13,417	14,856	15,682	14,686	14,680	14,342
Other Unavailable Inventories	14,776	11,877	14,648	12,557	12,836	8,977	9,988	8,294	8,797
Pipeline Fill	4,813	4,046	8,202	12,747	14,816	17,022	35,854	43,176	44,743
Pipeline Operating Requirements	6,446	6,702	4,158	7,983	11,162	9,701	15,651	8,758	10,139
In Transit—Truck, Tank Car, Barge & Tanker from Domestic Source	6,462	6,030	8,265	7,239	8,173	7,926	6,150	4,928	6,435
Total Unavailable Inventories	75,233	73,592	86,991	91,794	103,539	99,146	117,041	120,294	125,192
Unavailable as Percent of Total Reported to NPC	50.2	41.0	39.5	36.5	35.2	25.7	27.2	33.6	28.2
Working Stocks and Available Inventories	74,670	106,643	133,292	159,656	190,588	286,694	313,107	238,178	318,062

[a] Source: Reference 13.

[b] Unfinished at refineries has been omitted because of change in Bureau of Mines method of reporting effective January 1, 1962.

Tankage is provided at all receiving terminals and delivery points. Product tankage is much greater than crude because of its widespread distribution. In contrast, crude pipeline fill (Table 15) is over 50 percent higher than products.

4.1.3.3 Grouping Systems--

A pipeline grouping system can be used advantageously in the analysis of loss and spill data and in the development and implementation of an effective spill prevention program. Various grouping systems exist such as those based on regional areas and districts or pipeline corridors. Other groupings might also be made based on individual states, pipeline size or age, etc. Regional areas and districts for widely used groupings, i.e., standard Federal regions, BOM refining districts, and Petroleum Administration for Defense (PAD) districts are shown in Figures 8 and 9. The number of reported liquid pipeline accidents reported to OPSO during 1975 are also shown in Figure 8.

Selection of a grouping system was based on a number of considerations such as:

- Pipeline location
- Pipeline age
- Number and volume of reported spills for regional and district locations
- Areas of high risk
- Implementation of spill prevention program.

Crude and product lines (See Appendix B - Pipeline Mileage by State - and Figure 5) are in widespread use with somewhat uneven distribution throughout most of the United States. Eleven states, i.e., Texas, Oklahoma, Kansas, Illinois, California, Louisiana, Wyoming, Missouri, Ohio, Pennsylvania and New Mexico account for over 76 percent of the pipeline mileage. Only Texas, however, has a significant proportion (over 10 percent) of total pipeline activity with over one-third of the crude lines, one-sixth of the product lines (Appendix B) and one-fifth of pipeline fill (Table 15). Similarly, the number of spills and losses reported to OPSO occurred throughout most of the United States with the greatest number of spills and largest amount of losses occurring in Texas.

A grouping system based on standard Federal regions was judged to be best for this study. The number and location of Federal regions were considered to be particularly well-suited for analysis and for implementation of a spill prevention. Spill statistics show that a particular oil pollution problem is generally confined to only a few Federal regions. This allows concentrated effort in a particular region for solution of a regional problem and also minimizes jurisdictional disputes. For example, areas of high concentrations of pipelines, of most accidents, and of high risk, such as offshore, are located in only a few Federal regions. Also, areas of

TABLE 15. PIPELINE FILL FOR PETROLEUM PIPELINES IN THE UNITED STATES JANUARY 1, 1977 AND JANUARY 1, 1974[a]

(Thousand barrels)

State	Gathering lines		Crude-oil trunklines		Total crude lines		Product lines	
	Jan. 1, 1977	Jan. 1, 1974	Jan. 1, 1977	Jan. 1, 1974	Jan. 1, 1977	Jan. 1, 1974	Jan. 1, 1977	Jan. 1, 1974
Alabama	6	10	169	161	175	171	4,358	4,246
Alaska	8	12	130	131	138	143	47	11
Arizona	-	1	450	446	450	447	727	727
Arkansas	70	76	702	699	772	775	1,002	985
California	499	509	3,048	2,970	3,547	3,479	1,291	1,379
Colorado	82	74	612	604	694	678	184	138
Connecticut	-	-	-	-	-	-	52	55
Delaware	-	-	-	-	-	-	14	28
Florida	6	5	42	35	48	40	84	62
Georgia	-	-	-	-	-	-	2,725	2,623
Idaho	-	-	-	-	-	-	228	228
Illinois	223	216	5,830	5,955	6,053	6,171	2,845	3,089
Indiana	31	34	1,579	1,541	1,610	1,575	1,743	1,687
Iowa	-	-	50	89	50	89	1,963	1,519
Kansas	818	678	3,824	3,670	4,642	4,348	2,760	r/ 2,484
Kentucky	117	144	1,725	954	1,842	1,098	17	14
Louisiana	751	495	4,386	4,097	5,137	4,592	4,089	2,924
Maine	-	-	421	405	421	405	24	24
Maryland and District of Columbia	-	-	-	-	-	-	510	511
Massachusetts	-	-	-	-	-	-	64	76
Michigan	156	64	4,604	3,963	4,760	4,027	790	802
Minnesota	-	-	4,662	4,762	4,662	4,762	568	r/ 583
Mississippi	56	52	3,111	3,120	3,167	3,172	4,016	2,387
Missouri	-	-	3,899	3,827	3,899	3,827	2,541	2,486
Montana	107	98	751	703	858	801	257	228
Nebraska	60	60	1,046	1,047	1,106	1,107	693	112
Nevada	-	-	-	-	-	-	106	92
New Hampshire	-	-	280	208	280	208	-	-
New Jersey	-	r/	-	-	-	r/	745	639
New Mexico	421	373	1,495	1,029	1,916	1,402	476	291
New York	8	13	77	132	85	145	440	449
North Carolina	-	-	-	-	-	-	1,383	1,383
North Dakota	52	48	894	943	946	991	194	183
Ohio	114	93	1,045	1,175	1,159	1,268	1,657	1,496
Oklahoma	1,042	1,116	4,356	3,981	5,398	5,097	2,932	r/ 2,548
Oregon	-	-	-	-	-	-	134	240
Pennsylvania	78	92	479	254	557	346	2,304	2,220
Rhode Island	-	-	-	-	-	-	3	3
South Carolina	-	-	-	-	-	-	593	833
South Dakota	-	-	-	-	-	-	147	147
Tennessee	-	-	1,235	880	1,235	880	208	184
Texas	2,969	3,129	21,995	17,764	24,964	20,893	7,614	r/ 7,162
Utah	23	28	328	309	351	337	103	r/ 106
Vermont	-	-	297	297	297	297	-	-
Virginia	-	-	-	-	-	-	1,533	1,535
Washington	-	-	115	108	115	108	544	500
West Virginia	99	120	75	84	174	204	91	72
Wisconsin	-	-	2,434	2,460	2,434	2,460	246	247
Wyoming	295	278	2,368	2,356	2,663	2,634	423	383
Total	8,091	r/ 7,818	78,514	71,159	86,605	78,977	55,468	r/ 50,121

r/ Revised.

---

[a] Reference 11.

TYPING GUIDE SHEET

BEGIN FIRST LINE OF TEXT HERE
CENTER OF PAGE
TOP OF IMAGE AREA
DROPPED HEAD: BEGIN SECTIONS HERE

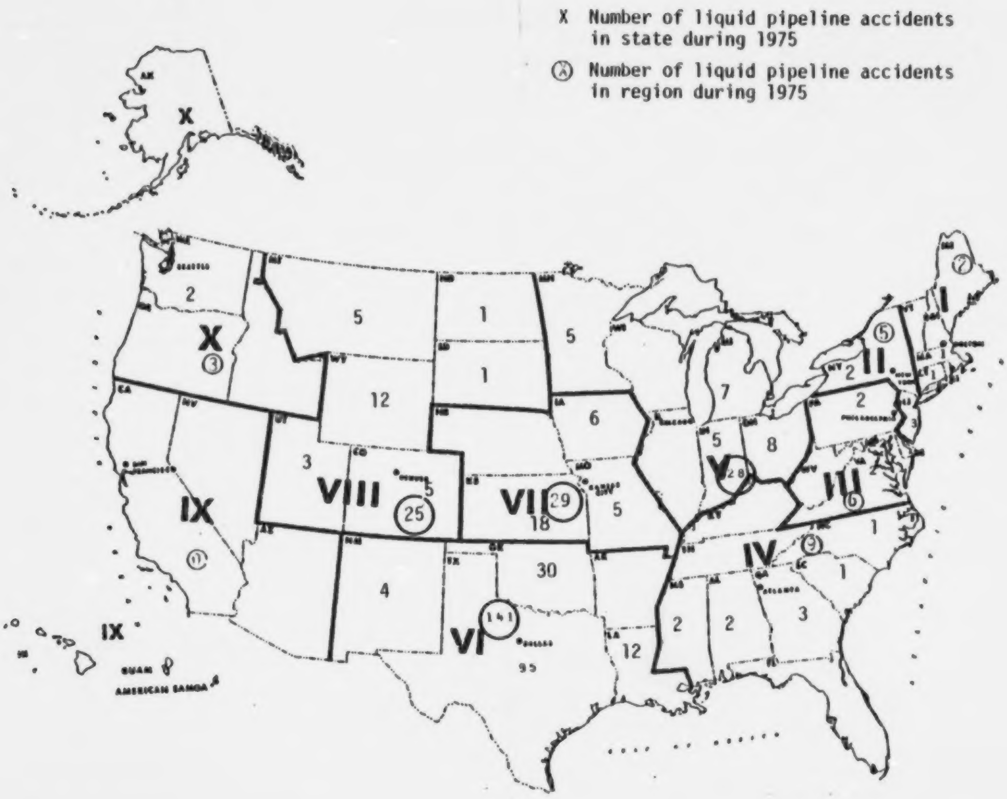
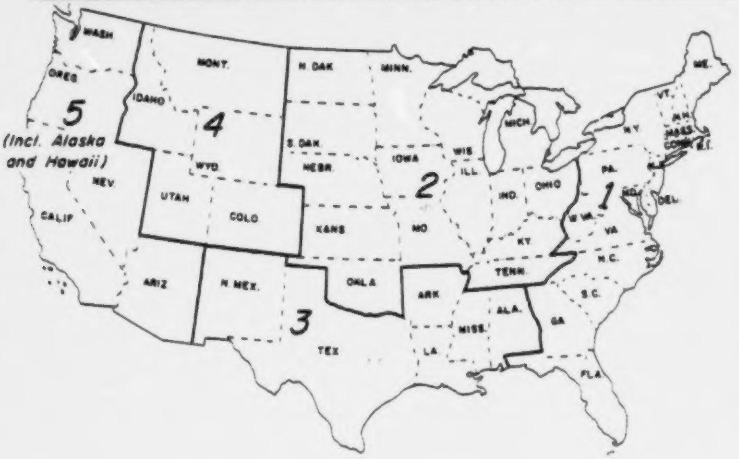

X Number of liquid pipeline accidents in state during 1975
Ⓧ Number of liquid pipeline accidents in region during 1975
X
③
2
IX
⑪
IX
GUAM
AMERICAN SAMOA
VIII
㉕
3
5
12
5
1
1
VII
㉙
18
6
5
5
VI
141
30
4
12
95
V
28
7
5
8
IV
③
2
2
3
1
1
III
⑥
2
3
1
II
⑤
2
I
②

Figure 8. Standard Federal regions (Commerce, EPA and HUD), with number of liquid pipeline accidents.

BEGIN LAST LINE OF TEXT

TYPING GUIDE SHEET

PETROLEUM ADMINISTRATION FOR DEFENSE (PAD) DISTRICTS


WASH
OREG
5
(Incl. Alaska and Hawaii)
CALIF
NEV
IDAHO
MONT.
4
WYO.
UTAH
COLO.
ARIZ
N. MEX.
3
TEX
N. DAK
MINN.
S. DAK.
NEBR.
IOWA
WIS.
ILL.
2
KANS
MO.
OKLA
ARK
MISS.
ALA.
LA
TENN.
KY
IND.
OHIO
MICH
1
PA.
N.Y.
W.VA.
VA.
DEL.
N.C.
S.C.
GA.
FLA.
ME.
VT.
N.H.
MASS.
CONN.
R.I.
N.J.

BUREAU OF MINES REFINING DISTRICTS

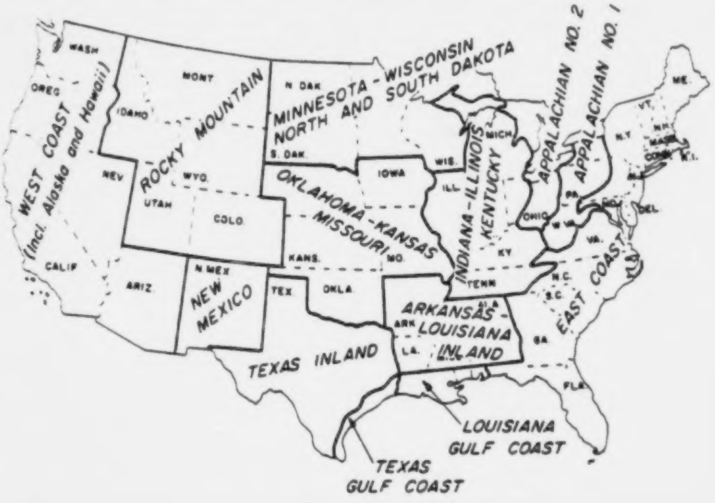

WEST COAST (Incl. Alaska and Hawaii)
ROCKY MOUNTAIN
MINNESOTA-WISCONSIN NORTH AND SOUTH DAKOTA
OKLAHOMA-KANSAS-MISSOURI
INDIANA-ILLINOIS-KENTUCKY
APPALACHIAN NO. 2
APPALACHIAN NO. 1
NEW MEXICO
TEXAS INLAND
ARKANSAS-LOUISIANA INLAND
EAST COAST
LOUISIANA GULF COAST
TEXAS GULF COAST
WASH
OREG
IDAHO
MONT
NEV
CALIF
UTAH
WYO.
COLO.
ARIZ
N MEX
N DAK
S. DAK.
IOWA
WIS.
ILL.
MICH
KANS.
MO.
OKLA.
TEX
ARK
LA.
ALA
TENN
KY
OHIO
W.VA.
VA.
PA.
N.Y.
DEL.
N.C.
S.C.
GA.
FLA.
ME.
VT.
N.H.
MASS.
CONN.
R.I.

Figure 9. Petroleum administration for Defense and Bureau of Mines refining districts. (Source: Reference 11.)

TYPING GUIDE SHEET

similar terrain and population densities are generally confined to specific regions. Most pipelines and spills, for example, are in region VI while most inland spills are concentrated in low population densities of regions VI, VII and VII and most offshore spills in regions VI and IX.

4.2 PETROLEUM SYSTEM - LOSSES AND SPECIFIC LOSS MECHANISMS

A number of significant loss mechanisms and false indications of petroleum losses exist in the petroleum transportation system in the United States. These petroleum losses can occur at any of the numerous system components such as those between the supply and the retail outlet shown in Figure 1.

The significant loss mechanisms that cause actual petroleum losses are the following:

- Evaporation (E)
- Leakage or spills (L)
- Admixture shrinkage (A)

These losses and typical measurement points (M) are indicated in Figure 10 for the petroleum system between the supply and refinery input.

Inaccuracies in petroleum measurement, calibration, estimates and accounting procedures, have resulted in an inability to determine how much crude is truly lost and to which mechanism (including undetected leaks). Of the specific loss mechanisms, only evaporative losses have been studied in detail. Estimates of these losses have been reported. However, studies are still being carried out to improve both evaporative measurements and equations for calculating the losses. Evaporative losses are difficult to estimate. For example, these losses vary widely depending on the production operations. Crude losses between the oil wells and crude oil storage (Figure 3) have not been and probably will not be accurately determined in the near future for a number of reasons. For example, leakage losses normally can only be detected by visual inspection or pressure testing because other means of leak detection are not available. The accuracy of the reported number of incidents and volume of petroleum lost is suspect. There has been only limited analysis on spill statistics and regulations on reporting spills to each government agency are different. Furthermore, the statistic reporting of these spills by each government agency are quite different. Thus it is difficult to compare and analyze statistical spill data.

In this section, the scope of this study for the petroleum system and losses is given. Then main sources of losses (leakage, evaporation and admixture shrinkage) between the supply and refinery input and the refinery output and marketing terminal are reviewed. Fault trees for pipeline spills are presented. False indications and uncertainties of losses are also identified.

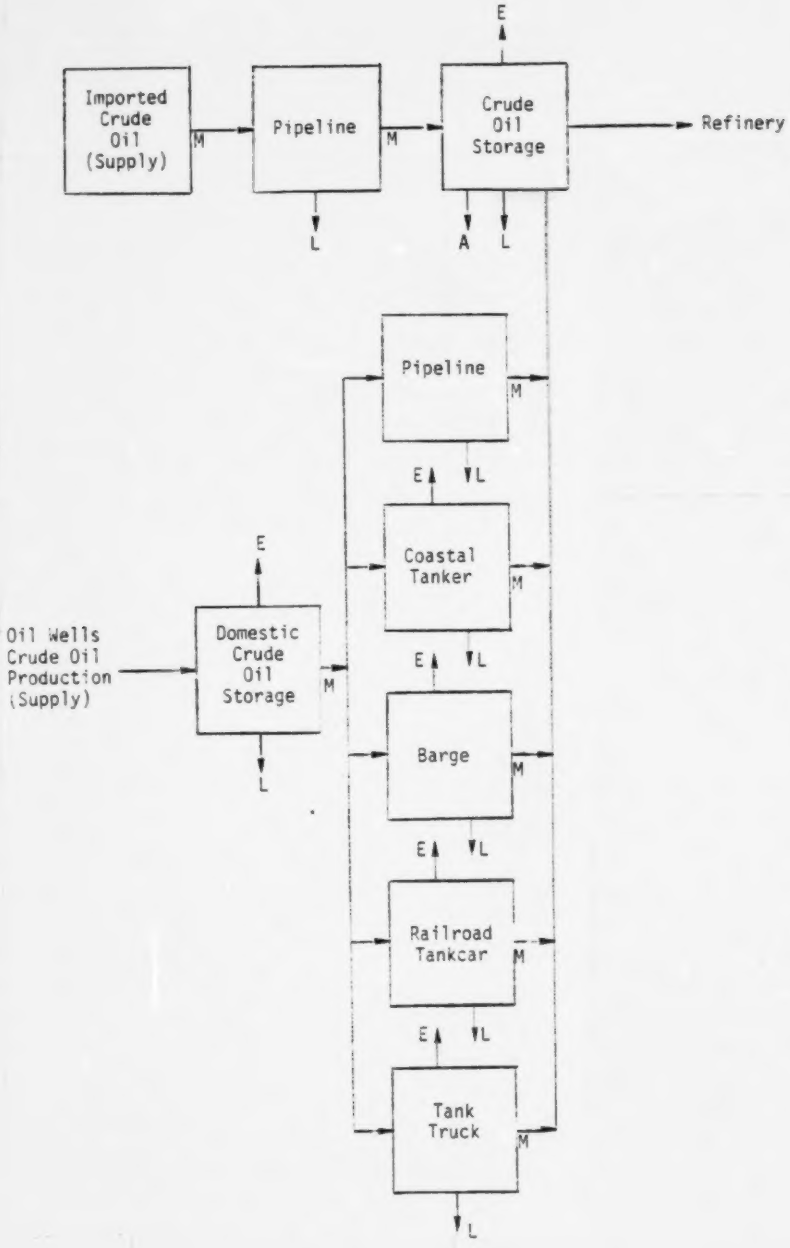

E
Imported Crude Oil (Supply)
M
Pipeline
M
Crude Oil Storage
Refinery
L
A
L
Pipeline
M
E
L
Coastal Tanker
M
E
Oil Wells Crude Oil Production (Supply)
Domestic Crude Oil Storage
M
L
E
L
Barge
M
E
L
Railroad Tankcar
M
E
L
Tank Truck
M
L

Figure 10. Major system components for crude losses between supply and refinery input.

4.2.1 Scope

It is beyond the scope of this study to determine all losses and losses from each individual petroleum transfer system and each system component. Hence, U.S. losses will be determined for the petroleum transportation system with the major losses, i.e., the pipeline transportation system.[a] The following losses and loss mechanisms are investigated in this study:

- Total losses of crude between the supply (crude oil storage, coastal tankers and barges) and refinery input via pipeline system (see Figures 1 and 10).
- Total losses of product between refinery output and marketing terminal via pipeline systems (see Figures 1 and 4).
- Individual loss mechanisms of the pipeline system between the crude supply (crude oil storage, coastal tankers and barges) and refinery input via pipeline system (see Figures 4 and 10).
- Individual loss mechanisms of the pipeline system between the refinery output and the marketing terminals via pipeline system (see Figure 4).
- Spill losses from pipeline systems of petroleum production operation (see Figure 3).

4.2.2 Losses

4.2.2.1 Spills--

Spills from pipeline systems are normally detected by visual monitoring or metering. These spills can occur at almost any location and for a variety of causes between the supply and refinery input and the refinery output and marketing terminal.

Main components and subcomponents that are the major sources of leaks from the pipeline system are given below.

---

[a] This pipeline transportation system would be expected to have the major losses because most petroleum is transported by crude and product pipeline systems. About 77 percent of the crude and 42 percent of the gasoline, and most of the crude and product are contained in pipelines and storage tanks.

1) Pipeline

- Line pipe
- Piping
- Valves
- Flanges
- Fittings
- Heaters
- Miscellaneous control, metering and monitoring equipment

2) Storage tanks

- Tanks
- Piping
- Valves
- Flanges
- Fittings
- Seals
- Pumps
- Miscellaneous control, metering and monitoring equipment

Spills from other pipeline system components include:

3) Pumps

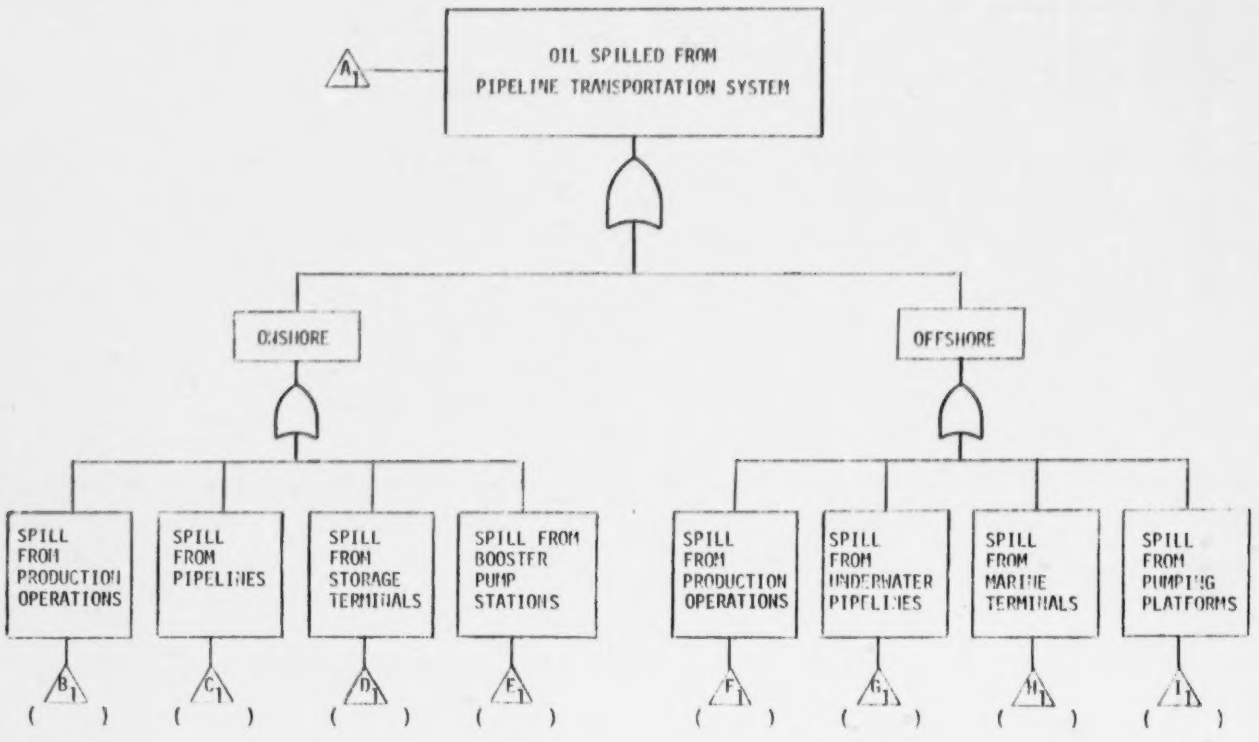
- Flanges
- Gaskets
- Seals
- Fittings
- Piping
- Miscellaneous control, metering and monitoring equipment

4) Production

- Gas-oil separators.

Fault trees are used here for an overview of the sources of leaks (failures) and in Section 6.3.2 for the detailed analysis of the risk of oil spills from petroleum pipeline systems. Fault trees[14] are logic diagrams that describe the ways in which component failures and other events can result, either alone or in combinations, in the top of the event trees. The top event is the undesired event. The probability of occurrence of the top event is desired. It can be calculated when all the failure probabilities of the basic events of the fault are known. These basic events on the tree are identified in Figure 6 and are combined through "AND" and "OR" gates.

A summary fault tree of petroleum spills from the petroleum pipeline system for the main areas and major systems (see Section 4.1.3) is given in Figure 11. A fault tree for the main source of the spills, the pipeline, is given in Figure 12. Specific values of the variables (a,b,c...)


A1
OIL SPILLED FROM PIPELINE TRANSPORTATION SYSTEM
ONSHORE
OFFSHORE
SPILL FROM PRODUCTION OPERATIONS
SPILL FROM PIPELINES
SPILL FROM STORAGE TERMINALS
SPILL FROM BOOSTER PUMP STATIONS
SPILL FROM PRODUCTION OPERATIONS
SPILL FROM UNDERWATER PIPELINES
SPILL FROM MARINE TERMINALS
SPILL FROM PUMPING PLATFORMS
B1
C1
D1
E1
F1
G1
H1
I1
( )
( )
( )
( )
( )
( )
( )
( )

() Spills per year

Figure 11. Fault tree A_1, oil spilled from petroleum pipeline system.

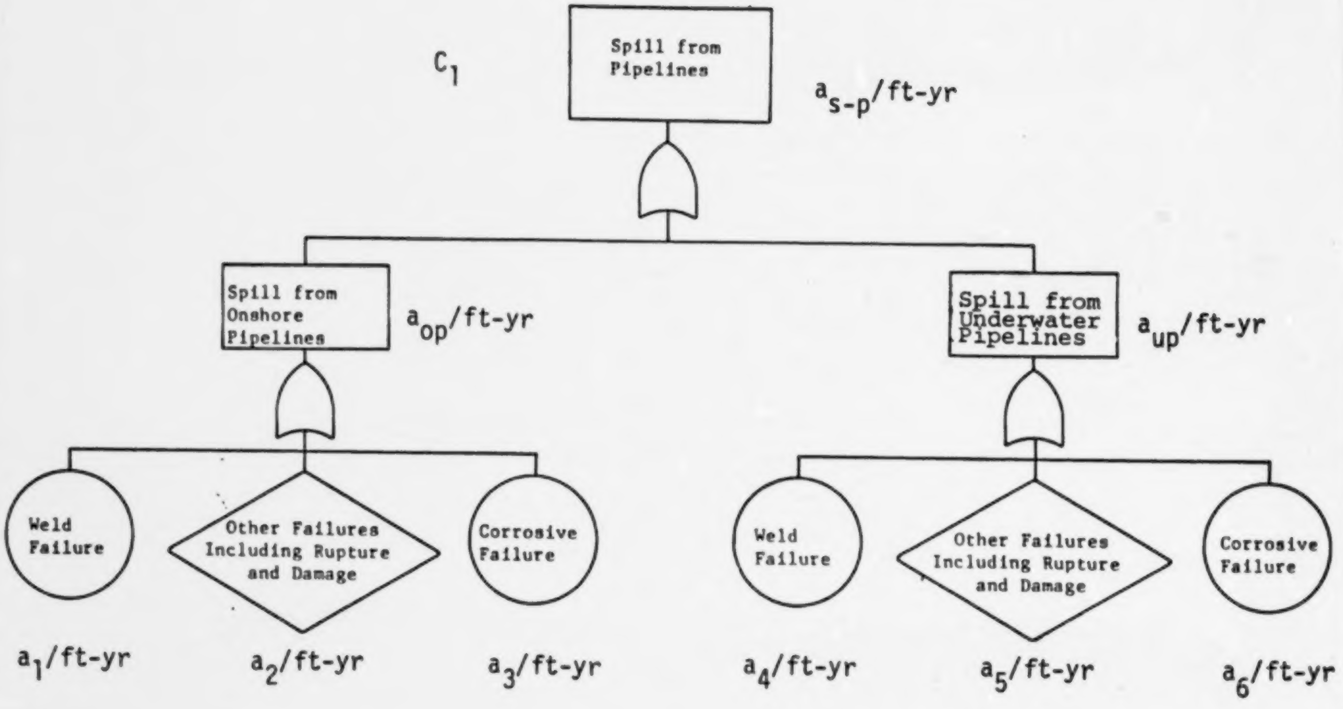

C1
Spill from Pipelines
a_{s-p}/ft-yr
Spill from Onshore Pipelines
a_{op}/ft-yr
Spill from Underwater Pipelines
a_{up}/ft-yr
Weld Failure
Other Failures Including Rupture and Damage
Corrosive Failure
Weld Failure
Other Failures Including Rupture and Damage
Corrosive Failure
a_1/ft-yr
a_2/ft-yr
a_3/ft-yr
a_4/ft-yr
a_5/ft-yr
a_6/ft-yr

Figure 12. Fault tree C_1, spill from pipelines. (Source: Reference 14.)

BEGIN FIRST LINE OF TEXT HERE
DROPPED HEAD; BEGIN SECTIONS HERE
CENTER OF PAGE
TOP OF IMAGE AREA
BEGIN LAST LINE OF TEXT
TYPING GUIDE SHEET

of spill frequency, volume, etc., for particular pipelines are given in Section 6.3.2.

4.2.2.2 Evaporation--

Evaporative losses for each loss mechanism and system component can be determined either by metering of fluids or calculations based on evaporative loss equations. Main sources of evaporative losses include:

1) Storage tanks

- Breathing
- Wetting
- Filling
- Emptying
- Boiling

2) Production

- Gas-oil separation
  - Flaring
  - Venting
  - Incomplete extraction of butanes and pentanes from gas
  - Storage
- Emulsion
  - Accelerated evaporation by heat
  - Storage
- Lease tank
  - Accelerated evaporation because of splashing
  - Storage

3) Transportation-pipeline

- Filling tanks
- Emptying of tanks
- Propulsion (pumping)
- Air eliminators
- Valves
- Fittings
- Connections

4.2.2.3 Admixture Shrinkage--

Admixture shrinkage[15] occurs when light hydrocarbons are mixed with heavy ones and result in a combined volume that is less than the volume of each individual hydrocarbon added separately. The resultant volume loss, however, is only an apparent volume loss and there is no loss of weight. Also, limited data indicates an increase in shrinkage with temperature increase and a decrease in shrinkage with a pressure increase. Admixture shrinkage occurs quite often, typically when light hydrocarbon products are blended into the crude stream. Figure 13 shows curves for estimating volume change when blending volatile hydrocarbon with crude oils.

4.2.2.4 False Indications--

False indications of loss[a] occur when a loss appears to occur but actually does not. Also, false indications may balance or cover up (by showing a gain) an actual loss. These false indications create either a constant bias or random uncertainty in the measurement of petroleum and in particular, losses.

4.2.2.4.1 Bias in Loss Measurement

A number of conditions may exist which indicate either a loss or gain, but in fact, are merely a bias in a specific direction in the petroleum measurement. These include:

- Use of incorrect coefficient of expansion. (Coefficient of expansion losses occur because the petroleum heats up and expands as it is shipped. Non-linear expansion of the petroleum occurs, but linear tables are used to correct this error. This results in an apparent loss at the delivery end of the pipeline.)
- Entrained free air in the line
- Incorrect back pressure on meters
- Higher prover temperature than the average daily temperature
- Human bias in reporting shortages rather than overages
- Human bias in reporting lower volume and incidents of spills.

4.2.2.4.2 Random Uncertainty or Inaccuracy in Loss Measurement

Uncertainties in petroleum loss measurements exist primarily because of metering limitations such as meter accuracies and calibration errors. However, other factors also contribute to this uncertainty. These include:

---

[a] These loss indications are described in more detail for the appropriate factor that contributes to measurement error in Section 4.3.

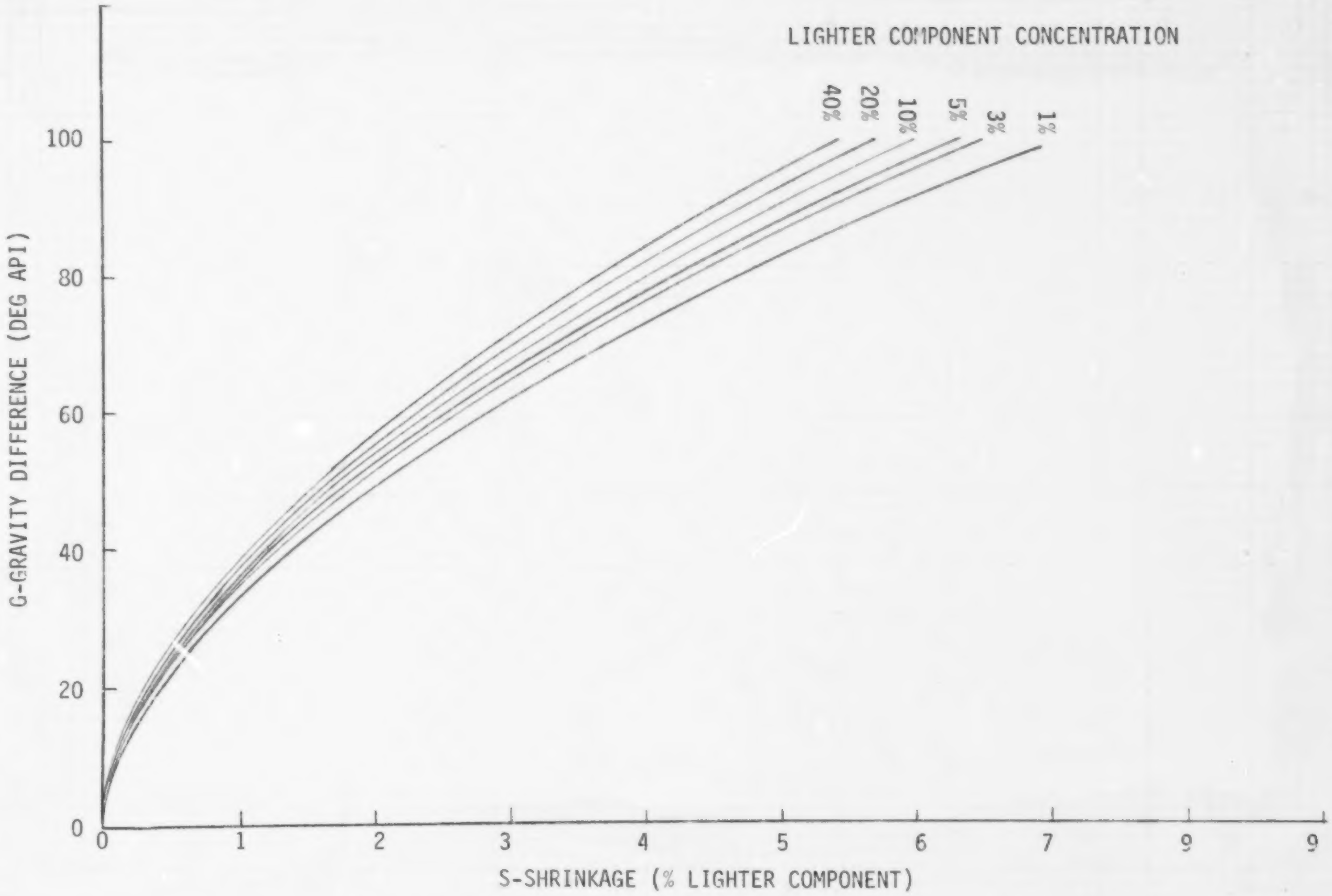


Figure 13. Curves for estimating volume change when blending volatile hydrocarbons with crude oil. (Source: Reference 15.)

- Variable conditions that affect meter performance
- Accounting errors
- Human errors
- Gravitation between tanks
- Inaccuracies in estimating the volume in the supply lines
- Physical changes in the volume of the fluids
- Changes in fluid between receipt and delivery.

4.3 MEASUREMENT

Accurate measurement of petroleum including quantities lost in transfer and storage is extremely important for both cost and environmental considerations. However, accurate measurements are difficult to obtain. The petroleum industry is currently in the process of improving measurements. Studies are being carried out in areas such as metering accuracies and techniques, expansion and loss tables and equations for computing evaporation losses. In spite of the current inaccuracies and errors in petroleum measurement, a significant amount of information on petroleum losses can be obtained from commonly used metering and accounting techniques. Furthermore, this information can be used to estimate losses nationwide.

Petroleum must be accurately measured to quantitatively determine either total losses or the total loss for a particular loss mechanism. Under ideal conditions, i.e., 100 percent pure petroleum, nominal variations in flow, and identical metering at each end of the pipeline system, receipt and delivery meters should provide identical readings. This would allow simple accounting procedures to determine overage and shortage resulting from either the total loss or a specific loss mechanism. This is not the case, however, and various factors such as:

- Meter errors
- Meter proving errors
- Variable conditions that affect meter performance
- Inaccurate correction factors
- Accounting errors
- Human errors and bias

contribute to an overall error in the measurement of petroleum. Additionally, changes in the fluid between receipt and delivery that cannot or are not measured, also contribute to the overall error.

On a short-term basis (monthly) or for a particular pipeline, these factors all contribute to some degree to measurement error, and an accurate determination of the true losses is extremely difficult using existing measurement and accounting techniques. On a long-term basis (yearly) or for a large number of barrels of throughput, i.e., yearly throughput of petroleum transported interstate, most of these factors would follow random normal distribution and the error would average out to almost zero. However, a number of factors that contribute to measurement errors are still present such as:

- Coefficient of expansion
- Admixture shrinkage
- Entrained free air in the lines
- Back pressure errors in meters
- Prover temperatures that are higher than the daily average temperature
- Evaporation
- Bias in reporting shortages rather than overages
- Measurement uncertainty.

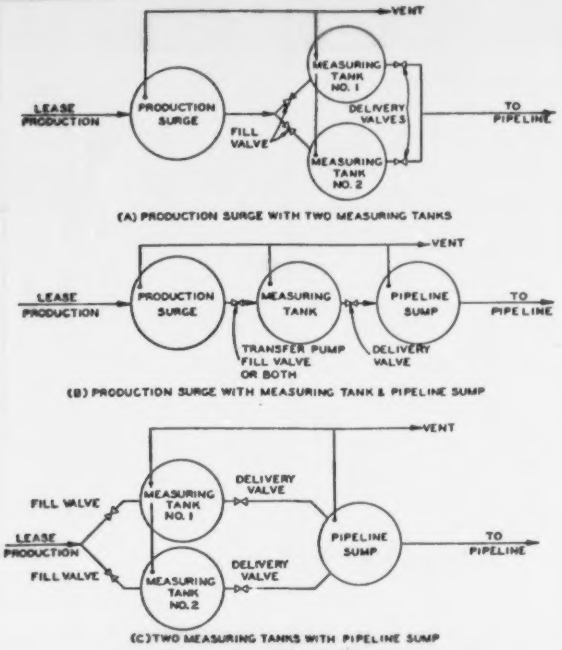
Measurement techniques and errors will be reviewed to ascertain the accuracy and limitations of measurements for quantifying petroleum losses. Techniques used in industry for both metering and accounting of petroleum will be reviewed and capabilities of these techniques evaluated. Then metering, meter proving, variable conditions that affect meter performance, correction factors, accounting, personnel reports (human errors and bias) and false indications are discussed in separate subsections. Changes in the fluid between receipt and delivery are discussed in Section 4.4.

4.3.1 Measurement Techniques--Metering and Accounting

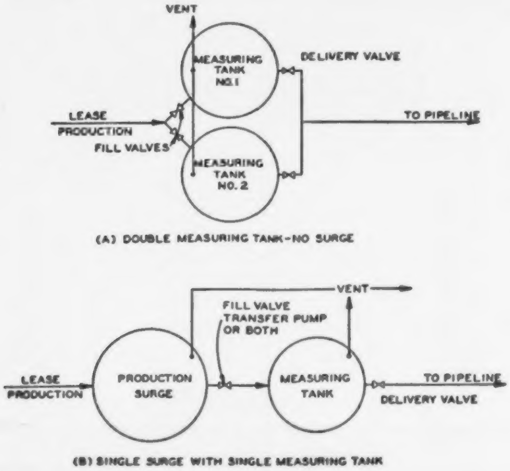
Petroleum losses, for the vast majority of U.S. pipelines, are measured with standard custody transfer systems at receipt and delivery. Figures 14 through 16 show the general arrangement of the commonly used Lease Automatic Custody Transfer System (LACT)[16]. Positive displacement meters (PD)[a] or turbine meters (TM) are normally used to measure the volume of petroleum that is received and delivered. These meters provide a display of gross barrels. In most systems, temperature changes of the petroleum due to changes in temperature barrels are also displayed on the meter. These values are either automatically or manually recorded on meter run tickets. Measurements of BS&W (bottom sediment and water content) are made separately with a sampler system, and net barrels are further corrected by this amount

---

[a] For brevity, metering errors for only PD meters (most commonly used meter) will be discussed in detail in this section to demonstrate the error problem. See also Section 4.5.


VENT
LEASE PRODUCTION
PRODUCTION SURGE
FILL VALVE
MEASURING TANK NO. 1
MEASURING TANK NO. 2
DELIVERY VALVES
TO PIPELINE
(A) PRODUCTION SURGE WITH TWO MEASURING TANKS
VENT
LEASE PRODUCTION
PRODUCTION SURGE
MEASURING TANK
PIPELINE SUMP
TO PIPELINE
TRANSFER PUMP FILL VALVE OR BOTH
DELIVERY VALVE
(B) PRODUCTION SURGE WITH MEASURING TANK & PIPELINE SUMP
VENT
FILL VALVE
MEASURING TANK NO. 1
DELIVERY VALVE
LEASE PRODUCTION
PIPELINE SUMP
TO PIPELINE
FILL VALVE
MEASURING TANK NO. 2
DELIVERY VALVE
(C) TWO MEASURING TANKS WITH PIPELINE SUMP

(A) Continuous Delivery to Pipeline.


VENT
MEASURING TANK NO. 1
DELIVERY VALVE
LEASE PRODUCTION
FILL VALVES
TO PIPELINE
MEASURING TANK NO. 2
(A) DOUBLE MEASURING TANK-NO SURGE
VENT
FILL VALVE TRANSFER PUMP OR BOTH
LEASE PRODUCTION
PRODUCTION SURGE
MEASURING TANK
TO PIPELINE
DELIVERY VALVE
(B) SINGLE SURGE WITH SINGLE MEASURING TANK

(B) Intermittent Delivery to Pipeline.

Figure 14. Typical system for delivery to pipeline.
(Source: Reference 16.)

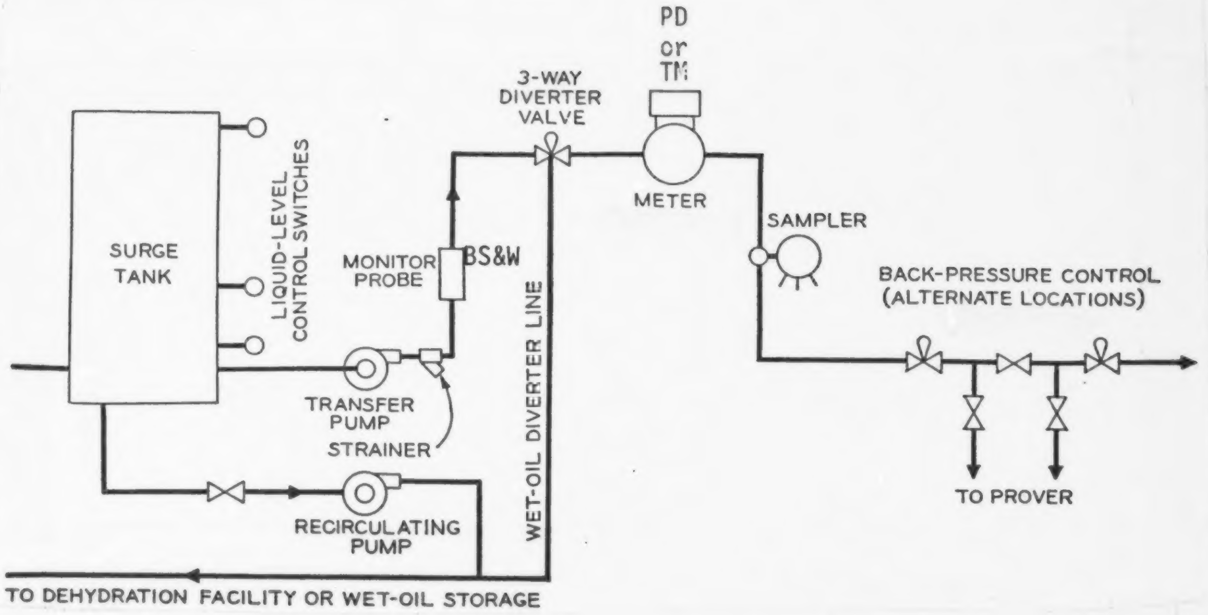
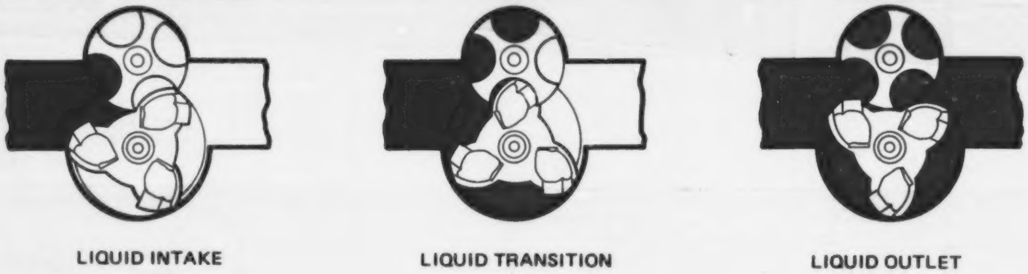
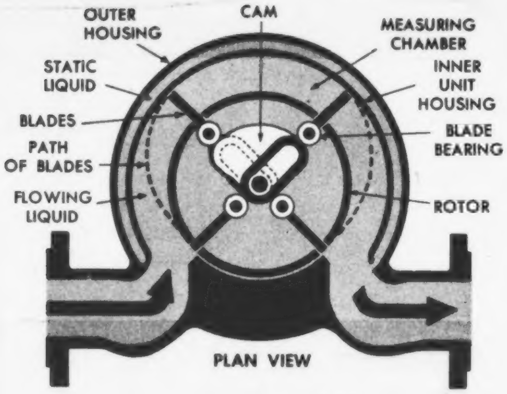

SURGE TANK
LIQUID-LEVEL CONTROL SWITCHES
MONITOR PROBE
BS&W
TRANSFER PUMP
STRAINER
RECIRCULATING PUMP
3-WAY DIVERTER VALVE
WET-OIL DIVERTER LINE
PD or TM
METER
SAMPLER
BACK-PRESSURE CONTROL (ALTERNATE LOCATIONS)
TO PROVER
TO DEHYDRATION FACILITY OR WET-OIL STORAGE

Figure 15. Typical PD meter LACT unit flow diagram. (Source: Reference 16.)


LIQUID INTAKE
LIQUID TRANSITION
LIQUID OUTLET

(A) Brooks-Birotor Meter Principle of Operational Diagram


OUTER HOUSING
CAM
MEASURING CHAMBER
STATIC LIQUID
INNER UNIT HOUSING
BLADES
BLADE BEARING
PATH OF BLADES
FLOWING LIQUID
ROTOR
PLAN VIEW

(B) Smith Meter-Principle of Operational Diagram

Figure 16. PD meters. (Source: References 17 and 18.)

TYPING GUIDE SHEET

on the meter run ticket. Meter prover systems are used to periodically prove (calibrate) the meters. Measuring-tank LACT (Figure 14) systems are used for a small percentage of the petroleum transported. Tanks or special vessels are the measuring devices in the automatic transfer of oil from leased to transporting carriers. Tank levels are manually read and then recorded on meter run tickets.

Petroleum losses can be determined from periodic monitoring of overages and shortages using standard petroleum accounting procedures. Overages and shortages are obtained by taking the difference between meter tickets for net barrels (corrected for temperature and BS&W) received into and delivered out of the system and correcting for changes in system inventory. For short-term monitoring (daily, weekly, monthly), this method may be used to determine if large losses exist. For long-term monitoring (yearly), small losses and in some instances the specific loss mechanism can be determined. Generally, most losses (shortages) are considered to be accounting errors but are normally investigated if the shortage exceeds 0.1 percent of throughput.

4.3.2 Metering Errors

4.3.2.1 Positive Displacement Meters--

Positive displacement meters are the most commonly used means of measuring flow in custody transfer systems. Two slightly different types of PD meters that are widely used in the petroleum industry will be briefly described.

A Brooks Instrument Division device, Figure 16(A), consists of two aluminum spiral fluted rotors within a measuring chamber dynamically balanced, but hydraulically unbalanced. As the product enters the intake of the measuring unit chamber, the two rotors divide the product into precise segments of volume momentarily and then return these segments to the outlet of the measuring unit chamber. During this "liquid transition," the rotation of the two rotors is directly proportional to the flow rate of liquid throughput. A gear train located outside the measuring unit chamber conveys mechanical rotation of the rotors to a mechanical or electronic register for gross totalization of liquid throughput.

A device by Smith Meter Systems, Figure 16(B), consists of a rotor with four evenly spaced slots that revolves on stainless steel bearings. The slots control the position of two blades that are at right angles to each other. As liquid flows through the meter, the rotor and blades revolve around a fixed cam. Ball bearings fixed to the blades roll around the cam, causing the blades to move radially. The successive movement of the blades, outward toward the case wall, forms a measuring chamber of precise volume between the blades, the rotor, the case wall, the cover, and the bottom of the case. A continuous series of these closed chambers is produced, four for each revolution of the rotor. Neither the blades nor the rotor contact the stationary walls of the measuring chamber.

In addition to the gross totalization function, PD meters normally include an accessory for automatic temperature compensation to provide net registration.[a] Net volume or net registration differs from the gross metered volume depending on the average liquid temperature and base temperature and the coefficient of expansion of the liquid. One typical temperature compensator system consists of the following: (1) bulb (that converts temperature change to linear motion) installed in the motor housing and exposed to the metered liquid; (2) a gravity selector (coefficient of expansion selector); (3) a main gearing system; (4) a secondary gearing system that includes an integrator; and (5) a mechanical register for net totalization of liquid throughput. Net registration operates continuously regardless of flow rate and temperature variations.

Assuming manufacturer recommendations on operating conditions, ranges, etc., are followed, typical performance specification of these meters are:

●	Linearity	± 0.1 percent over rated flow range
●	Accuracy	± 0.25 percent over flow range ± 0.2 percent over 5 to 1 flow range
●	Repeatability	± 0.02 percent over flow range
●	Temperature	± 1°F over temperature range.

Errors in PD meters can result from a variety of sources. Some of these are:

- Slippage - passage of unmetered fluid through the internal tolerances (clearance between rotating piece and stationary piece so no metal contact) or the meter
- Rotor drag - changes of rotor speed caused by internal or external loading effects
- Measurement volume changes
- Temperature compensator nonlinearity and hysteresis
- Component damage or malfunctions
- Meter wear.

The effect on the performance of the meters depends on these sources and on a variety of conditions such as operating ranges, fluids and environment. If the meters are regularly proved (calibrated) with line fluids at typical line operating conditions, the performance can be improved greatly and effects of error sources can be significantly reduced. Proving is normally done at periodic intervals, i.e., weekly or bi-weekly, for custody transfer systems and accuracies of about ± 0.02 percent to ± 0.05 percent are routinely achieved. In many cases, however, operating conditions may be changed and meters not proved for these conditions, i.e., line fluids may be changed or significant variations of line operating conditions may occur. Even in the case of a meter without defects this may result in accuracies of ± 0.25 percent or worse.

---

[a] Net registration is defined in the U.S. as liquid volume at a referenced base temperature of 60°F.

Discussions with petroleum industry personnel indicated that one of the main complaints with PD meters was their poor reliability. This is a problem even though most meters have an automatic shudown that occurs if the meters are defective and do not register a certain amount of throughput. Malfunctions can result in a variety of errors. For example, the main components that malfunction are the stacks which contain the temperature compensator, printing head and other mechanical parts. The temperature compensator unit is considered to be the weakest link in the stack and in the PD meter. This component requires high maintenance and malfunctions cause a substantial error in the measurement. For example, a measurement error of only 1^{o}F is equivalent to a volume error of about 0.04 percent for a typical crude.

4.3.2.2 Tank Gauging--

Tank gauging is less accurate than PD or turbine meters. It is a standard method for metering in custody transfer, but it is used to measure less than 10 percent of the petroleum transferred. Thus, tank gauging errors, although quite high, do not significantly affect the ability to accurately determine nationwide petroleum losses.

A variety of errors affect the overall measurement and limit the accuracy to about ± 0.5 percent. These errors include:

- Measurement errors - inability to measure accurately such things as height of liquid, container size and average temperature.
- Gravitation between tanks - leakage in a valve between two tanks can cause a loss of product in one tank and a gain in another that may not be observed.

4.3.2.3 BS&W Metering--

Bottom sediment and water content metering is very inaccurate and this has not been improved upon for many years. This is due to two main problems. First, the sample is collected and put into a centrifuge which can be read out only at increments of 0.05, 0.10, 0.15, 0.2, 0.3, 0.4, 0.5 and so on. Since one must typically read in increments of 0.1, a roundoff error of 0.1 percent is possible for each measurement. Secondly, there is a large sampling error in BS&W primarily because three sampling steps are required for a sampling. The steps are as follows: (1) take sample out of line; (2) take sample from the original sample; and (3) take a third sample for the centrifuge. Each sampling step is subject to being non-representative. Also, for low transport velocities[19] the original sample taken out of the line is affected because of non-uniform distributed dispersion. In theory, BS&W sampling errors are purely random and should not contribute to an error over a large period of time (1 year). However, on a daily or monthly basis, the error can be substantial. On an individual line, there can be a significant error problem because the BS&W on one end of the line might not agree with the BS&W on the other end.

BS&W measurement, in general, is very inaccurate and is considered the weakest link in the measurement of petroleum at receipt and delivery. BS&W content in delivered petroleum ranges between 1 and 2 percent of the total volume. Since BS&W readings are required in the correction for net barrels, there can be significant errors in the net barrels correction. This error occurs regardless of the other metering accuracies achieved. BS&W errors can be evaluated on individual lines by comparing the BS&W reading at each end of the line for separate batches.

Because of BS&W inaccuracies, leak detection systems (see Section 5) that monitor gross barrels can be much more accurate than comparable systems that measure net barrels.

4.3.3 Meter Proving Errors

Performance in this report primarily pertains to the accuracy or repeatability of a measurement for a specific meter sensitivity or meter factor. This is determined originally by manufacturer calibrations and after installation by user provings (calibrations) at one or more flow conditions for the fluid transported. Normally, meter proving is done near the operating conditions for the fluid transported during the day on a weekly or bi-weekly basis and a single meter factor is used.

Meter proving over the range of variable conditions for the fluid transported and then correcting the data (ideally by computer or by manual conversion of a graph or meter factor curve) is often done. This accounts for some of the variable effects on the meters and significantly reduces errors. Even if this is done, some errors may not be corrected. For example, external temperatures may vary greatly over a 24-hour or weekly time interval and it would be extremely difficult to account for these variations.

4.3.4 Variable Conditions that Affect Meter Performance

There are many variable conditions that could affect the performance of PD meters. These include:

- Meter wear, damage, or internal deposits
- Flow rate
- Viscosity

- Temperature
  - Liquid
  - External
  - Liquid expansion
  - Vaporization
  - *Temperature and viscosity*
- Lubricating qualities of the liquid
- Liquid pressure
- Liquid density
- Entrained free air
- Torque
- Back pressure
- Other.

Effects of many of these variable conditions cannot or are not normally accounted for and a significant error band is generally present.

Each of the variables identified are discussed briefly and an estimation of the errors given in instances where the errors are significant and/or the qualitative effects are known. Also, error sources are identified that do not follow a random normal distribution.

4.3.4.1 Meter Wear, Damage, Internal Deposits--

Meter wear, internal damage and internal deposits can change the volume of the PD measurement chamber and affect slippage. Thus, incorrect volume measurements and unknown amounts of liquid may pass through the meter unmeasured. Foreign matter from sources such as solids in the bottom of the tanks or in the liquid itself is particularly harmful to the meter. Normal change from meter wear between proving may amount to 0.1 percent.

4.3.4.2 Flow Rate--

Variations in the flow rate have a significant effect on the error over the flow range of the meter. This can be seen, for example, in Figure 17 where a typical accuracy curve is given for a PD meter. This error is mainly due to slippage. It is less repeatable and inaccurate at the flow rates because of a capillary seal effect. This effect is usually minimized by operating the meter at the medium and high ranges and re-proving the meter as conditions change. Meter factor may be used from a curve that has been developed rather than reproving.

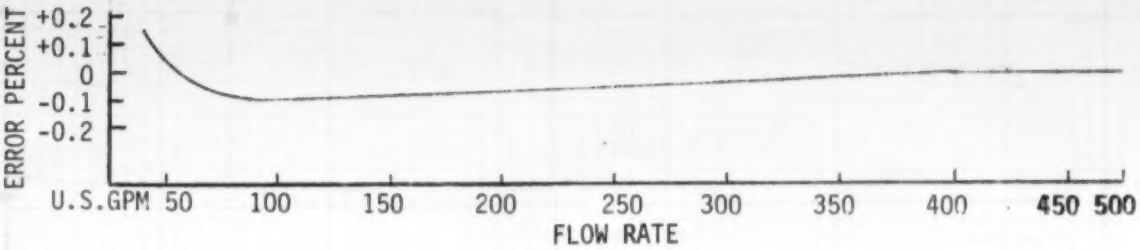


Figure 17. Typical accuracy curve for a PD meter.

4.3.4.3 Viscosity--

Variations in viscosity affect the meter performance by changing the slippage of the liquid through the meter. Viscosity changes cause either thickening or thinning of the liquid and this affects the volume that can slip through the tolerances of the meter unmeasured. For example, as the temperature of a liquid increases, liquid thinning occurs and more fluid can slip through the meter. Viscosity variations can occur from changes in the liquid, in the temperature, or the liquid and the temperature. Re-proving the meter when a fluid change occurs is the best way to correct for this error although plots of meter factors as a function of viscosity are often used. Viscosity effects are almost negligible for light products. With a heavy crude, such as a number 6, viscosity variations can result in a small error.

4.3.4.4 Temperature--

Variations in temperature have the most significant effect on meter performance and cause various errors. These variations occur primarily from the following:

- Liquid temperatures
- External temperatures
- Liquid expansion
- Liquid vaporization
- Viscosity.

The combinations of the effects of many of these variables in many instances are inseparable. This can cause significant errors that cannot be detected or corrected even by frequent proving.

Liquid Temperature--With liquid temperature variations, thermal expansions or contractions occur in the meters that are not necessarily linear or precisely known. This is caused by dissimilar or different materials and results in mechanical clearances that vary. Both the volume of the measuring chamber and slippage can be affected. Proving the meter at or near the operating temperature of liquid helps to minimize this error.

Typically, this error would be in the same direction for similar custody transfer PD meters and receipt and delivery and may not significantly affect overages and shortages. However, the magnitude of this error increases and may not be in the same direction (affecting overages and shortages) for very dissimilar or different internal meter materials. This occurs, for example, when different types or sizes of meters are used at receipt and delivery.

External Temperature--External temperature is conveyed through the metal to the meter measuring elements. These temperatures cause thermal expansion or contraction of the meter by an external temperature gradient. At the same time, a different internal temperature gradient from the liquid also causes thermal expansion or contraction. (See previous subsection.) For example, a higher external temperature (120°F) causes thermal expansion of the meter while a lower internal fluid temperature (70°F) causes contraction. Both external and fluid temperature measurements are required for accurate meter factors to determine the volume of the fluid. This is not normally done. Furthermore, meter proving is usually done only during the day when the external temperature is always higher than the average temperature for a 24-hour period. Thus, the effects of external temperature typically are not known and not corrected for in meter proving.

Liquid Expansion--Temperature variations of the liquid cause variations in volume that depend upon the characteristic thermal coefficient of the liquid. This variation has the most important effect on meter performance of any of the variable conditions. This is because an error of only 1°F is equivalent to a volume error of about 0.04 percent for a typical crude. Proving is usually done close to the temperature of the fluid transported and this tends to reduce measurement errors to small errors that are of a random normal distribution.

The temperature bulb of the temperature compensator unit is not calibrated separately because it is not a significant source of error as long as the meter is proved at the temperature at which you are operating. Periodically, it is removed and installed in a temperature bath and calibrated at true temperature. If large temperature variations (> 10°F) occur between meter provings, use of a single meter factor may result in a substantial error, i.e., about ± 1.125°F or a ± 0.05 percent volume error for each PD meter. If, instead of the temperature compensator unit, a manual reading of temperature is carried out, an arithmetic correction is applied and an even larger error can be expected.

Temperature and Viscosity--Variations of external temperature, liquid temperature and viscosity of fluids result in overall effects on the meter performance that are difficult to determine and in many cases inseparable. The following example will demonstrate the problem. If the fluid temperature is increased, the viscosity of the fluid will decrease. The fluid will thin down and will increase squirm through the meter (slippage) and not be measured at the same time; the clearances in the meter will decrease. Thus the fluid attempts to pass through the meter, i.e., because of the lighter fluid and increased slippage, and at the same time the blade clearances expand and become tighter and tend to reduce slippage. These effects compensate one another so as to reduce slippage. The overall effects of these variations are dependent on the particular meter because one meter may expand at a different rate than another primarily because of different materials.

4.3.4.5 Liquid Pressure--

Meter performance is affected only by changes in operating pressures that are high enough to affect the dimensions of the meter by elastic deformation. A 100 psi pressure change causes an error of about 0.04 percent. Assuming typical operating conditions, the pressure has to be off a great deal before this variation becomes significant. Since crudes have considerably higher viscosity than products, the accuracy of meters in crude service normally varies less with flow rate than metered products. If pressure changes are significant, the measurement ticket value must be corrected by the multiplication factor Cpl.

Pressure pulsations and excessive surges as well as excessive pressures caused by thermal expansion can cause errors in the meter reading. Normally, surge tank, expansion chambers, relief valves or other protective devices are used to minimize these problems.

4.3.4.6 Entrained Free Air--

Entrained free air in the liquid occurs mainly at unloading facilities and can affect the drag of the meter rotor. As the air strikes the measuring elements, the air will be metered and the metered air will momentarily speed up the meter. This occurs because there is less resistance to air moving through the meter than the liquid and results in higher readings because of the speed-up of the meter and the measurement of air.

4.3.4.7 Back Pressure--

If back pressure is off, the meter should read low. However, the value of this error is difficult to determine and is, in fact, debated as an error source. However, on turbine meters back pressure is a significant source of error. A formula for minimum back pressure is recommended by API to correct for back pressure variations.

4.3.5 Inaccurate Correction Factors

Inaccurate correction factors can cause errors in a number of measurements that can affect petroleum loss values. The most significant one is the common use of an inaccurate coefficient of expansion α for the liquid.

4.3.5.1 Coefficient of Expansion α--

Field measured volumes are corrected for expansion from ambient temperature at the measurement point to the volume at 60°F and 14.7 psia using ASTIM-IP[20] Petroleum Measurement Tables. These tables give densities linear with temperature. This is based on the value of the expansion coefficient α, which is assumed to have a linear relationship $\alpha = 1/V(dV/dT)_p$, that is a function of standard density at 60°F and 14.7 psia. This simple relationship of α to temperature and standard density was shown to be incorrect by Kurtz[21]. Downer and Inkley[22] made coefficient of expansion measurements for crude that showed α values of the 1952 ASTIM-IP tables to be about 8 percent low. However, products were fairly representative of the curve given from the ASTIM-IP tables. Figure 18(A) shows the expansion coefficient of the curve from ASTIM-IP tables and those measured for crude oil and products. Figure 18(B) shows the expected calculation error for a 1°F temperature range.

Use of inaccurate coefficient of expansion tables causes a very substantial hypothetical loss to occur for petroleum transfer. This is because the average temperature before transfer (receipt) is higher than the average temperature after transfer (delivery). Both volume measurements are currently corrected using the incorrect coefficient in the ASTIM-IP tables and a "hypothetical" or "apparent" loss results.

4.3.6 Accounting Errors

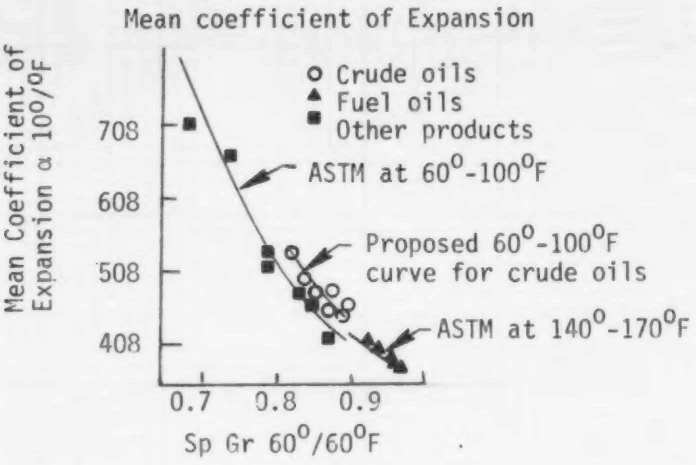
Petroleum accounting provides records of receipts, deliverables, inventories, overages and shortages, etc., that are quite useful in estimating overall system losses and establishing the possible existence of leaks. Accurate records of losses or leaks appear to be simple to obtain, but in actual practice various error sources make this quite difficult to achieve. A few of the accounting procedures that are normally carried out include:

- Receipt and Delivery - Periodic totalizing meter tickets for net barrels received into and delivered out of the system.
- Inventory - Periodic totalizing of tank gauging records and line capacity.
- Overages and Shortages - Periodic computing of the difference between receipt and delivery tickets and then correcting for inventory changes.

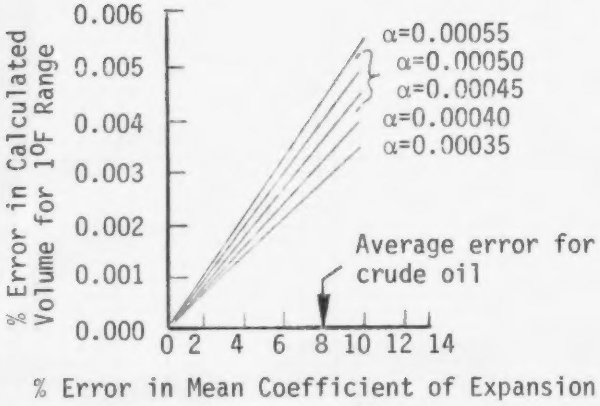
In practice, these procedures often cannot be carried out without the possibility of numerous errors (usually small) that can make daily, weekly or monthly accounting quite inaccurate. Over a long period of time, however, most accounting errors would be expected to follow a random normal distribution and average out close to zero. Yearly accounting would be expected to be an order of magnitude more accurate than monthly accounting. Sources of accounting errors are discussed in the subsections that follow.

4.3.6.1 Inability to Make all Measurements at the Same Time--

All meters (receipt, delivery, tank gauges) in a system are normally read every ten days and/or the last day of each month. Since it is almost impossible to read all meters at the exact scheduled time, significant



(a) Expansion Coefficients--Table ASTM-IP and Measured



(b) Error Calculations Table for Coefficient of Expansion

Figure 18. Error curves and calculations for inaccurate correction factors of the coefficient of expansion α for liquids (Source: Reference 22).

errors result. For example, if a custody transfer meter that is measuring 1000 bblh is read 15 minutes late an error of 250 bbl would occur.

4.3.6.2 Damaged Meter--

If a damaged meter is found, the meter is assumed to have gone bad between the last time the meter was read or proved. This can present a large error for short-term accounting, particularly for meters that monitor large throughput.

4.3.6.3 Pipeline System Complexity--

Petroleum pipeline systems in the U.S. vary from simple single line systems to very complex multiple systems. The latter systems often have numerous inputs and metering locations, use different lines and transport different fluids. It is extremely difficult to implement error-free accounting on these complex systems, particularly over a short time, i.e., weekly, monthly.

4.3.6.4 Tank and Line Inventory--

Measurement of the inventory in pipelines and tanks is typically quite good and the relative error quite small because the line is usually full and the volume does not change appreciably. Tank gauges are inaccurate (about ± 1/2 percent) but tanks usually contain only a small portion of the petroleum of throughput (< 3 percent). Thus if a worst case reading error of 1 percent on all tanks in the U.S. were five billion barrels, inventory would be about 150 million barrels. Thus a 1 percent reading error of the tank gauges would result in an inventory error of about 1,500,000 barrels or a system error of 0.03 percent. Over a long period of time, however, most gauging errors would be expected to follow random normal distribution and average out close to zero.

4.3.6.5 Personnel Errors--

(See Section 4.3.7.)

4.3.7 Human Errors and Bias

Human errors and bias can contribute to both the overall accounting errors and actual errors in spill reporting. These errors cannot be estimated quantitatively and range from mistakes in reading meters to incorrect inputs to the computer.

Gravitation between storage tanks, for example, can result in loss of product from one tank and a gain in another if valves between any two tanks leak. Loss or gain in a tank may not be detected (see also Section 4.3.6.4).

Some of the most important errors are bias errors in reporting petroleum losses. Two of these are particularly significant. First, there appears to be a tendency to report shortages rather than overages because overages are difficult to explain. Second, there is a tendency to underestimate the size of small spills, particularly those close to the minimum reportable size. This latter error exists primarily because of the extreme difficulty in accurately estimating the actual spill size. This error can result in reports of the incidents and volume of spills that are too low.

4.4 CHANGES IN PETROLEUM BETWEEN RECEIPT AND DELIVERY

Changes in petroleum can occur between receipt and delivery that may not or cannot be correctly measured by normal custody transfer metering. This creates problems in determining what is being measured, particularly for long lines that are of large diameter. These changes can result in significant errors in volumetric measurement particularly over short periods of time, i.e., days, weeks.

4.4.1 Fluid Heating

Fluids at receipt in storage tanks are usually at a higher average temperature than at the delivery point. This temperature difference is estimated to be about 10^{o}F. The major effect of this temperature difference is in the error that results from use of the inaccurate coefficient of expansion α. A 10^{o}F difference for crude, for example, would result in a 0.04 percent error in the measured volume. Also, petroleum entering the pipelines and cooling before being taken out can shrink. For example, cooling of 5^{o}F can cause shrinkage of approximately 0.25 percent in volume and result in substantial errors if temperature measurements at either end of the line are in error. The temperature difference between fluids at each end of the line may be quite different for an individual line or lines in certain areas.

Petroleum heats up and expands as it is transported because the energy put into the pipeline is transferred to the petroleum. This heating effect depends upon a number of factors such as flow rate, pumping and pipeline dimensions. If the pipeline is operated at a high rate, friction builds up. Crowding of the pipeline (working at capacity or above) also tends to generate a large amount of heating. These effects become more pronounced as the size of the line increases because the large pipeline mass transfers off less of the heat that is generated.

Effects of external temperatures and internal fluid heating during transport are difficult to estimate and measure for individual lines. Thus, differences in fluid temperatures at each end of the line present difficulties in accurately measuring the true volume of the fluid.

4.4.2 Water Settling

If BS&W is high, i.e., 1 to 2 percent or more, water tends to settle at the bottom of the line. This can result in a significant difference in the BS&W at each end of the line and result in a larger error in net barrels. As noted previously, at low transport velocities there is a non-uniform distributed dispersion of water, solid particles and hydrocarbons which affect BS&W sampling accuracy.

4.4.3 Admixture Shrinkage

(See Section 4.2.2.3.)

4.4.4 Miscellaneous

Other less significant changes that can occur include:

- Cavitation
- Viscosity changes due to temperature
- Vaporization if line pressure goes too low.

4.5 TOTAL MEASUREMENT SYSTEM ERROR

The measurement accuracy for individual pipeline systems must include the combined effect of the various measurement errors (see Section 4.3) and fluid changes between receipt and delivery (see Section 6.4). This information is necessary in determining the minimal spill loss that can be detected. Means of obtaining a value for the measurement accuracy are presented in Section 4.5.1. An estimate of the minimal spill loss that can be detected is presented in Section 4.5.2 for a simple line.

4.5.1 Means of Computing Measurement System Error

In general, the total system error will be greater than any of its individual components. Hence, it is important to account for significant errors of individual components. This can be done as follows: First, estimate the error (in standard deviations) of each individual component (E_c), i.e., flow meters, pressure transducers, etc. This is done by computing the square root of the sum of the squares of the individual components

$$E_c = \sqrt{\sigma_1^2 + \sigma_2^2 + \ldots \sigma_n^2}$$

where $\sigma_1 \ldots \sigma_n$ = errors of individual components. Then computing the total systems error (E_t) by taking the square root of the sum of the square of individual error component,

$$E_t = \sqrt{E_{c1}^2 + E_{c2}^2 + \ldots E_{cn}^2} \quad .$$

4.5.2 Computation of Minimal Detectable Spill Loss for a Simple Pipeline System

Estimates of the overall measurement error, which consists of the combined errors of typical metering (leak detection equipment, etc.), line fluctuations and other items, are necessary in order to determine the minimal spill loss (in barrels) that can be detected. Assuming the simple line and instrumentation identified in Figure 19(A), the total system error is computed in Figure 19(B).

4.6 LOSS STATISTICS

Results on measurement and fluid changes in Sections 4.3 and 4.4 indicate that total losses and individual loss mechanisms potentially can be determined for the U.S. petroleum industry from existing loss statistics. However, system inaccuracies caused by both limitation and errors in measurements and unaccounted for fluid changes are inherently present and must be considered. In cases where there is a large throughput and many measurements are taken over a large period of time, most random normal errors tend to be negligible and reasonable loss estimates can be obtained.

In this section, total petroleum losses and specific loss mechanisms are studied based on nationwide statistics. Information is obtained primarily from U.S. Government agencies and programs, foreign government agencies,[a] major oil companies, and studies of statistics of spills and other losses.

Statistics on overall total losses are reviewed in Section 4.6.1. Data in this section indicate that substantial losses do exist. Loss statistics on the specific loss mechanisms of oil spills and factors affecting these losses are discussed in detail in Section 4.6.2. Causes and factors relating to failures of various pipeline systems components are studied.

4.6.1 Total Losses

No published reports, that are available, directly estimate total petroleum losses in barrels. Petroleum information reported by oil companies and published in statistics by the U.S. Government is in barrels received into and delivered out of the petroleum transportation systems. This information does not specifically identify shortages or losses in barrels. However, indirect estimates of these losses can be made from available U.S. Government statistics.

---

[a] Foreign statistics will also be reviewed. In some countries, pipeline regulations are much more stringent than in the U.S. (See Appendix A.2). Also pipeline age, installation, etc., are not typical of those in the U.S. Thus, spill statistics may differ from those in the U.S.

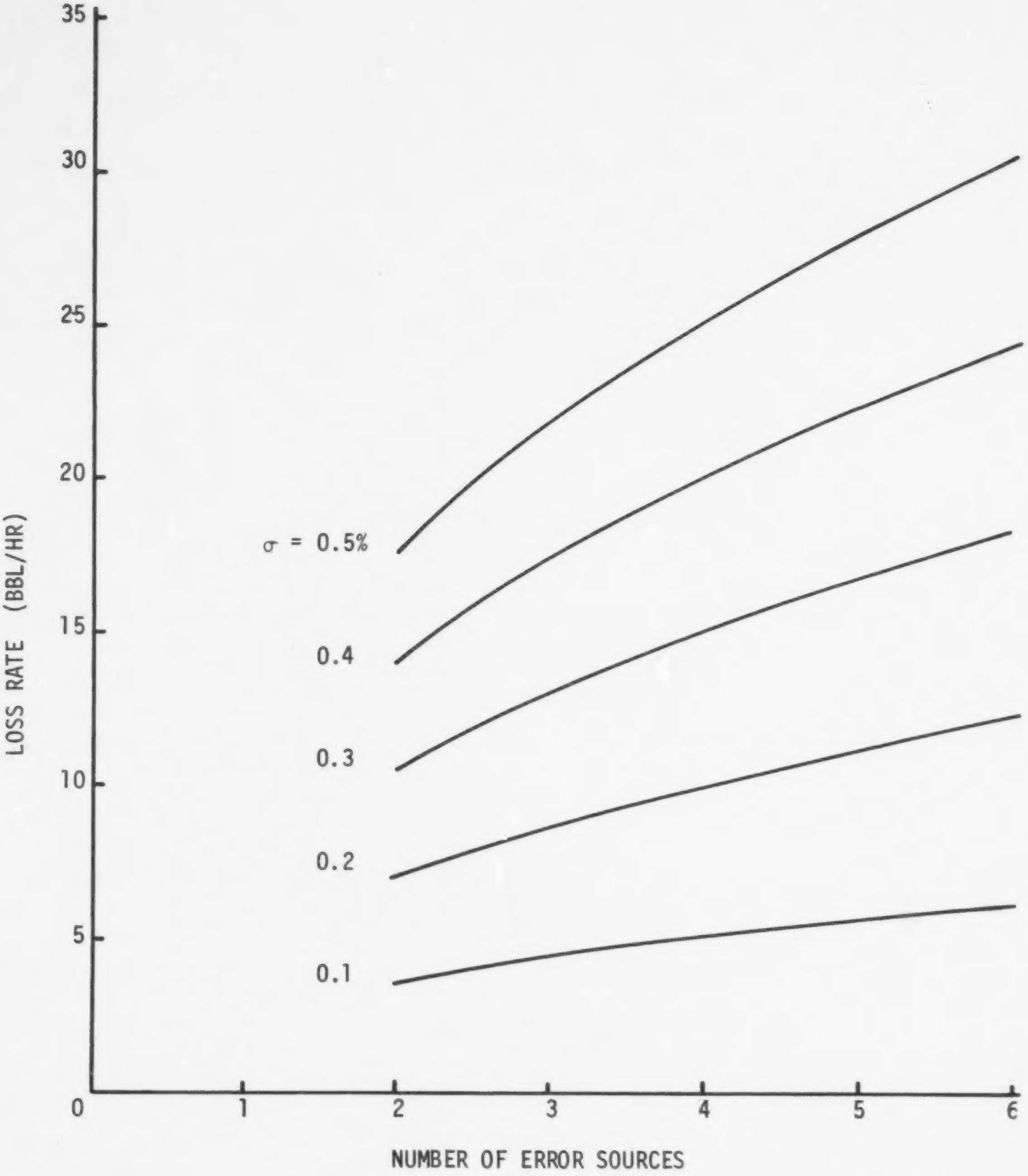


Figure 19. Minimum detectable spill loss for a simple pipeline system.

Also, data on petroleum loss allowances or tariff deductions (in percent of throughput) published by U.S. companies to cover actual pipeline system transportation losses can be used to directly estimate total losses.

4.6.1.1 ICC Statistics--

Total petroleum losses can be estimated from ICC transport statistics.[6] Table 16 shows ICC statistics for the total barrels of crude and product received into and delivered out of U.S. pipeline systems (pipeline, storage tanks, etc.) engaged in the interstate transportation of petroleum for the 12-year period between 1964 and 1975. Data are included here for approximately 170,000 miles of pipeline and an average trip length of about 300 miles per barrel. Petroleum losses are obtained by taking the difference between the received and delivered barrels. Average losses were relatively consistent and, except for 1965, ranged from 0.17 to 0.30 percent of barrels received into the system between 1964 and 1976. An average loss of 0.21 percent (standard deviation 0.07 percent) occurred over this period. For the year 1975, this average loss would amount to about 20 million barrels of oil. These losses in Table 16 can only be used as estimates, particularly on a yearly basis, primarily because the inventory is not included in these ICC statistics. Assuming inventory changes generally vary in a purely random way (see Section 4.1.3.2), it would be expected to average close to zero over a long time period.

Unpublished ICC information[23] on overages and shortages in the dollar cost of oil is reported by individual companies. These statistics are indicative of substantial losses of petroleum. Unfortunately, these overages and shortages are given in dollars and the barrel cost is not provided. Furthermore, for some companies overages and shortages reported may not show a loss even if an actual loss exists. This is due to different reporting companies. For example, some companies assume a certain percentage loss allowance between receipt and delivery and this is included as part of the normal operating expense. If the actual loss does not exceed the set loss allowance, no shortages are reported. Other companies report the actual overages and shortages. Regardless of various shortcomings, the existing information provides a rough estimate of the cost of lost oil. A substantial effort would be required, however, to obtain an accurate estimate of the cost of lost oil. Inquiries would have to be made to the individual companies for reporting procedures and barrel costs and the data compiled. Even then, it is uncertain that dollar costs could be converted to an accurate estimate of barrels lost.

4.6.1.2 Petroleum Loss Allowance-Tariffs Published by U.S. Companies--

Tariffs by pipeline transportation companies are of sufficient accuracy that they can be used to determine total losses in pipeline transportation systems. Tariffs or petroleum loss allowances are charged by shippers to cover all actual losses from evaporation, shrinkage, and all other unavoidable losses during transportation, so that the shipper always has enough oil on hand to deliver a certain amount of oil. The tariff is

TABLE 16. THROUGHPUT AND LOSSES FROM ICC TRANSPORT STATISTICS

Year	Number of Barrels Received into System	Number of Barrels Delivered Out of System	Loss Barrels	Loss %
1964	5,575,851,696	5,565,112,394	10,739,302	0.19
1965	5,867,582,598	5,863,651,079	3,931,519	0.07
1966	6,251,704,887	6,238,192,221	13,512,666	0.22
1967	6,813,740,133	6,800,423,951	13,316,182	0.20
1968	7,289,434,872	7,268,759,226	20,675,646	0.28
1969	7,755,292,825	7,741,815,221	13,477,604	0.17
1970	8,163,531,445	8,146,684,754	16,846,691	0.21
1974	9,359,988,000	9,333,340,000	26,648,000	0.28
1975	9,787,030,000	9,757,103,000	29,927,000	0.30
Average Loss				0.21
Standard Deviation				0.07
1964-1970	47,717,134,000	47,624,636,000	92,498,000	0.19
1974-1976	28,505,842,000	28,431,053,000	74,800,000	0.03

quantity of oil deducted from the amount received for shipment and the balance is the net quantity deliverable.

Loss allowance values are determined in a number of different ways by pipeline companies. Some companies' charges are based on a previous year's experience and their tariff may change yearly. Other companies base their tariffs on long-term loss figures and other considerations.

Tariff information is provided by individual companies in their Rules and Regulations of Transport of Liquids. The following example is a typical deduction charge by Laurel Pipeline Company in their rules and regulation #8.

> "Gauging, Metering, Testing and Deductions
>
> Quantities of petroleum products shall be determined at the Carrier's option by tank gauges and computations made from tank tables showing 100 percent of the full capacity of the tanks or by the Carrier's positive displacement meters. Such quantities shall be corrected to a temperature of 60°F.
>
> Shipper and consignee shall have the privilege of being present or represented during gauging, metering reading, meter calibration and testing of shipments by Carrier.
>
> One-half percent of all petroleum products received for transportation at point of origin shall be deducted and retained by Carrier to cover losses due to shrinkage and evaporation incident to pipeline transportation, and the net balance will be the quantity deliverable to consignee."

Tariff deduction information is furnished to the ICC and is summarized for individual companies in a private publication.[24]

The tariff charge varies from one company to another. Typical rates range from about 0.05 to 0.50 percent. Published tariffs for a typical sampling of U.S. companies is given in Table 17. Shell pipeline, for example, has a tariff charge of 0.15 percent for crude and Teromo's new 30-inch pipeline has a tariff of 0.1 percent. Currently, the average industry tariff rate for a sampling of interstate lines (Table 17) is about 0.22 percent[a] (about 0.16 percent for crude and 0.33 percent for product) of the petroleum received into the system. This amount is in reasonable agreement with the 0.21 percent average loss from ICC statistics. In the 1960's, the loss allowance used was about 0.1 percent, but has been revised upward based on recent shipper experience.

---

[a] Excludes tariff rates (about 6 percent of companies) that are in excess of 0.50 percent.

TABLE 17. PETROLEUM LOSS ALLOWANCE FROM TYPICAL U.S. PIPELINE COMPANIES IN PERCENT OF GROSS PETROLEUM SHIPPED

Crude		Product	
Company	Loss Allowance (%)	Company	Loss Allowance (%)
Arapahue	0.25	Airforce Pipeline Inc.	0.50
ARCO	0.20	American Petrofina	0.20
Belle Fourche	0.20	Amoco	0.50
Buckeye	0.25	ARCO	0.50
Butte	0.15	Buckeye	
Chevron	0.25	Chase Transportation	0.10
Explorer	0.25	Gulf	0.50
Pipeline Limited	0.10	Laurel	0.50
	0.05	Pinto	0.25
	0.10	Plantation	0.125
	0.05	Phillips	0.25
Jawhawk	0.10	Southern Pacific	0.25
Keanai	0.25	Texas Pipeline Co.	0.25
Lakhead	0.05	Williams Pipeline	0.25
	0.05	Gulf	0.50
	0.10		
Phillips	0.15	Average Tariff	0.33
Osage	0.10		
Ohio Oil Gathering	0.50		
Sohio	0.10		
Tomahawk	0.20		
Texoma	0.10		
Shell Pipeline	0.15		
Pure Transportation	0.25		
Williams	0.10		
Wesco	0.20		
Average Tariff	0.16		

4.6.1.3 BOM Statistics--

Bureau of Mines statistics[3] on production, imports, exports, storage, refinery and consumption in the U.S. includes a loss estimate of 0.1 percent of the total crude supply for losses between supply and disposition. The percentage, which agrees with the early ICC loss tariff, was chosen based on an undocumented study in the early 1960's by BOM, API and others. Individual loss mechanisms that make up the 0.1 percent value cannot be identified.

BOM annual reports also provide statistics on total losses. After careful and extensive review, it was determined that these statistics do not lend themselves to analysis and were not considered further.

4.6.2 Oil Spills

Statistics of reported oil spills on land and water in the United States normally include spill location, source, cause, type of oil, volumes discharged, company, etc., and are collected by the following four Federal government agencies: (1) Office of Pipeline Safety and Operations; (2) Environmental Protection Agency (EPA); (3) United States Geological Survey (USGS); and (4) United States Coast Guard (USCG). Each has a specific jurisdiction that in total encompasses essentially all spills. In some instances, similar data are collected by more than one agency. Also, jurisdiction of spills is uncertain in some cases.

In this study, spill statistics are separated into the following six reporting areas:

(1) Onland pipelines for aboveground spills that are in excess of 50 barrels and occur in a carrier's transportation system. Includes inland spills that are on land and in water--OPSO Department of Transportation.[25,26]

(2) Offshore pipelines carrying oil produced and owned by companies that do not operate the pipeline. Statistics apply only to transportation related pipelines--OPSO.

(3) Onshore and offshore facilities not related to transportation. Includes inland pollution of water, streams, underground water supplies, etc.--EPA collects information by a Spill Prevention, Control and Countermeasure (SPCC) file that was started in 1975.

(4) Inland spills that occur on Federal lands. Reporting system began in 1974--USGS.[27,28]

(5) Federally controlled outer continental shelf. Reporting system began about 1966 to provide information for regulations for safe drilling and production practices in outer continental shelf--USGS.

(6) All spills from coastal, river and Great Lakes and all transportation-related facilities. Includes all offshore spills, no matter what size, from all sources (including pipelines) out to three miles and spills in excess of 50 barrels beyond three miles. Also, oil spills that pose a threat to the water. Pollution Incident Reporting Systems (PIRS) began in 1971 by USCG.

PIRS data should include all OPSO-reported spills in the U.S. waters and large spills reported by the USGS. Spill data for these areas and the indicated Federal government sources were used for statistical analysis of the spills in the United States.

For comparison purposes, oil spill statistics from various individual states and some foreign countries were used. States include California, Colorado, Louisiana, Mississippi, New Mexico, Oklahoma and Texas. These sources are described in Appendix C of Reference 30. Foreign sources include spill statistics for cross-country pipelines in Europe[31,37] by the Stitching CONCAVE and in Canada[38] by the Task Force on northern oil development.

Caution must be exercised in using any of these statistics because a number of deficiencies and defects exist both in the reporting of spills and in the compiling of spill reports by the various Government agencies. Some of these are:

- Errors in reporting
- Non-compliance with required reporting
- Different reporting requirements by Government agencies, such as:
  - Spill size
  - Spill details
  - Exclusion of spill reports for some types of line pipes or systems
- Difference in interpretation of spills by Government agencies.

A recent report[1] by the U.S. General Accounting Office on pipeline safety identifies a number of deficiencies and weaknesses in spill reporting and analyses. Deficiencies in spill reporting are also identified in Reference 40. These problems are considered in this study and attempts are made to minimize potential errors by various means such as comparing statistics from more than one source or estimating unreported events.

In the spill analysis carried out in this section, statistical data are corrected for errors such as non-reporting of spills, pipelines not covered by regulations, and spill sizes not covered in the reporting. Possible errors and unusual trends in U.S. spill statistics are discussed also. A number of pertinent studies (References 14, 30, 41, 42, 43, 44, 45, 46, 47, 48, 49, 50) on risks and on oil spill trends have been carried out and pertinent results are presented in this section.

Oil spill statistics on the incidents of failures of pipeline system components and the causes of failures in the United States are examined in Sections 4.6.2.1 through 4.6.2.5. Factors relating to the number and frequency of these incidents (pipeline geometry, age, etc.), volume and severity of incidents (fatalities, injuries, etc.) are also presented. Particular emphasis is placed on the OPSO and USGS statistics for analysis of pipeline system spills. Statistics presented in Section 4.1.3 such as pipeline mileage in-service by category and throughput are used in the examination of spill statistics for various pipeline parameters. Statistics on reported cross-country oil spillages in Europe and Canada are examined in Section 4.6.2.6 and compared with U.S. spillage.

Results from this section provide the basic information for the oil spill risk analysis in Section 6. Based on statistical data presented in this section and in Section 4.6.1, the total oil spillage from pipeline systems (see Section 4.1.3) is estimated in Section 4.7.

4.6.2.1 Loss Mechanisms--Inland and Offshore Spills in the U.S. (OPSO Statistics)--

Statistics from the Office of Pipeline Safety and Operations of reported liquid pipeline transportation system accidents are available because all petroleum transportation companies are required by the Code of Federal Regulations, Title 49, Part 195[7] (Appendix A) to notify OPSO if there is a reportable spill incident and to submit a report on DOT form 7000-1 (see Appendix A, Figures A-1 and A-2). Incidents defined by Title 49, Part 195.50 that must be reported for any failure in a pipeline system where there is a release of commodity transferred resulting in:

(a) Explosion or fire not intentionally set by the carrier.
(b) Loss of 50 or more barrels of liquid.
(c) Escape to the atmosphere of more than five barrels a day of liquified gas.
(d) Death of any person.
(e) Bodily harm to any person resulting in one or more of the following:
  (1) Loss of consciousness.
  (2) Necessity to carry the person from the scene.
  (3) Necessity for medical treatment.
  (4) Disability which prevents the discharge of normal duties or the pursuit of normal activities beyond the day of the accident.
(f) Property damage of at least $1,000 to other than the carrier's facilities, based upon actual cost or reliable estimates.

It should be noted, however, that besides the 50 barrel spill minimum, OPSO spill data does not include all inland and offshore pipeline system spills. That is, it applies only to transportation-related pipeline and does not include, for example, spills occurring at offshore production facilities such as a gathering net. Additionally, many gathering lines are operated that do not come under regulation. These include:

- Transportation through a pipeline by gravity.
- Transportation through pipelines that operate at a stress level of 20 percent or less of the specified minimum yield strength of the line pipe in the system.
- Except for Subpart B of this part, transportation of petroleum in onshore pipelines in rural areas between a production facility and a carrier's trunkline reception point.
- Transportation in offshore pipelines which are located upstream from the outlet flange of each facility on the Outer Continental Shelf where hydrocarbons are produced or where produced hydrocarbons are first separated, dehydrated, or otherwise processed, whichever facility is farther downstream.

Reportable information includes date, time, location, carrier information, density of area, origin of release of commodity, cause, death, injuries, damage material, dollar value of property damage, commodity, installation year, pipeline size, barrels lost, and other pertinent line pipe information.

A review of the actual reported information indicates a number of deficiencies and discrepancies, such as:

- Gathering and trunk pipelines cannot be distinguished for most incidents.
- Production and transportation lines cannot be distinguished for most incidents.
- Leak duration is often not reported.
- Volume of oil spilled cannot be accurately assessed.
- Submitted reports do not always include answers to all questions; thus the number of incidents are not consistent with some categories.

Also, there appear to be slight discrepancies in data as reported by USCG and USGS for some of the same incidents.[38] Additionally, OPSO provides pipeline mileage data for gas lines but not liquid pipelines. Thus data obtained from BOM such as miles of pipe in service (see Section 4.1.3) were used as an aid in the analysis. None of these deficiencies and discrepancies were sufficient enough to affect analysis and the outcome of the conclusions on petroleum spills.

In the sections that follow, spill statistics are first examined to determine the overall magnitude of the spill problem, i.e., the number and volume of reported spills. Then the pipeline system components that fail most often, i.e., line pipe, are also studied. This latter analysis is carried out because results of an analysis based on data from the total pipeline system alone, as is done in other studies, can be misleading and can culminate in incorrect conclusions and ineffective recommendations. Finally, factors relating to the probability of spill incidents and severity are presented. The number of incidents and volume spilled are examined for the following:

- Type of fluid
- Mileage
- Throughput
- Pipeline diameter
- Depth of cover
- Fatalities and injuries
- Property damage.

These and other factors such as:

- Pipeline coating
- Corrosion control
- Procedures
- Areas where spill occurred
- Elapsed time
- Miscellaneous

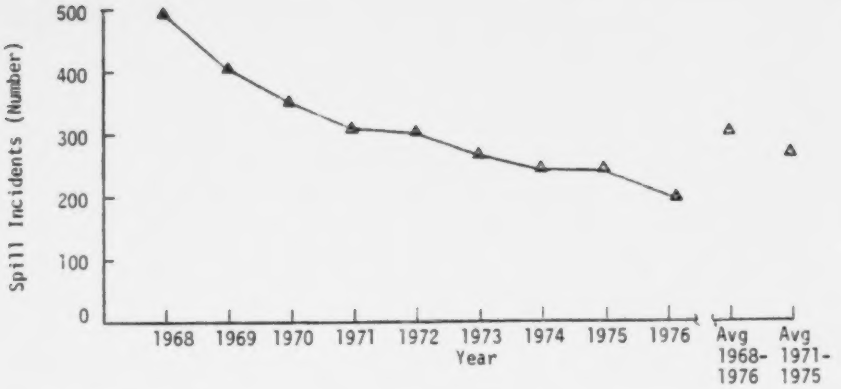
are also discussed in Section 6.3. This same general approach is used in the study of spills based on data from other sources. (See Sections 4.6.2.2 through 4.6.2.6). However, not all factors are examined because either available data are not suitable for analysis or there is no need for further analysis.

4.6.2.1.1 Overall Magnitude of Spill Problem--Frequency and Volume of Spills

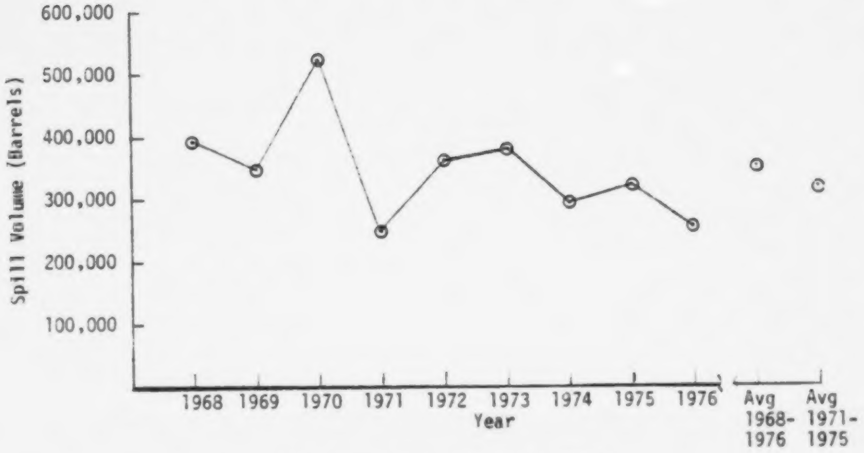
A summary of statistics on spills from petroleum pipeline systems for all accidents reported to OPSO for the 9-year period between 1968 and 1976 is presented in Table 18. More detailed statistics are given in Appendix B. Data show that a significant number of incidents were reported and a substantial volume of petroleum lost. The average number and volume of spills between 1968 and 1976 were 317 incidents and 346,007 barrels respectively; this decreased to 280 incidents and 319,628 barrels for the more recent 5-year period between 1971 and 1975. Figure 20 shows a rapidly declining year-by-year trend for spill incidents and a slightly declining trend for spill volume for the period between 1968 and 1976.

4.6.2.1.2 Pipeline System Component Failures--Incidents and Volume Spilled

Statistics on spills from components of the petroleum transportation system are presented in Table 19 and illustrated in Figures 21 and 22. Data



(A) SPILL INCIDENTS VERSUS YEAR



(B) VOLUME SPILLED VERSUS YEAR

Figure 20. Spill incidents and volume versus year for petroleum pipeline system accidents reported to OPSO between 1968-1976.

TABLE 18. SPILL STATISTICS FOR PIPELINE SYSTEMS TRANSPORTING LIQUIDS IN THE U.S. FOR INCIDENTS REPORTED TO OPSO BETWEEN 1968-1976[a]

	Number of Spills									Number of Spills (bbls)								
	1968	1969	1970	1971	1972	1973	1974	1975	1976	1968	1969	1970	1971	1972	1973	1974	1975	1976
External Corrosion	216	155	149	102	75	72	52	57	41	69,904	70,878	45,232	29,925	40,475	32,637	21,399	37,073	31,954
Internal Corrosion	16	17	30	22	25	14	15	16	10	7,863	5,725	15,616	12,445	38,988	11,455	3,901	2,853	3,249
Operational Causes[b]	14	15	20	22	24	16	28	22	20	13,237	22,687	32,541	22,830	46,185	63,144	20,957	26,619	40,155
Equipment Malfunction or Failure[c]	18	18	6	10	10	16	10	27	15	8,146	18,153	16,273	16,266	6,298	11,891	13,474	20,981	5,866
Severe Weather[d]	4	5	1	5	14	14	9	2	6	6,919	5,535	2,500	4,860	31,799	22,975	6,299	11,356	4,365
Construction Defects[e] or Material Failure[f]	80	58	46	56	62	56	29	26	20	95,758	99,899	45,265	65,646	59,948	169,510	53,485	94,440	51,847
External Impact[g]	106	102	75	73	86	74	90	81	78	114,578	96,409	81,531	74,907	123,896	63,600	120,347	116,273	102,587
Miscellaneous & Unknown	45	33	20	18	13	11	23	29	19	76,167	24,325	282,891	18,178	13,070	4,153	53,781	9,829	15,014
TOTAL	499	403	347	308	309	273	256	260	209	392,581	343,691	521,849	245,057	360,654	379,365	293,643	319,423	255,037

	Spills by Cause as Percent of Total Number of Spills[h]									Spills by Cause as Percent of Total Volume of Spills[h]								
	1968	1969	1970	1971	1972	1973	1974	1975	1976	1968	1969	1970	1971	1972	1973	1974	1975	1976
External Corrosion	43.3	38.5	42.9	33.1	24.3	26.4	20.3	21.9	19.6	17.8	20.6	8.7	12.2	11.2	8.6	7.3	11.6	12.5
Internal Corrosion	3.2	4.2	8.6	7.1	8.1	5.1	5.9	6.2	4.8	2.0	1.7	3.0	5.1	10.8	3.0	1.3	0.9	1.3
Operational Causes[b]	2.8	3.7	5.8	7.1	7.8	5.9	10.9	8.5	9.6	3.4	6.6	6.2	9.3	12.8	16.6	7.1	8.3	15.7
Equipment Malfunction or Failures[c]	3.6	4.5	1.7	3.2	3.2	5.9	3.9	10.4	7.2	2.1	5.3	3.1	6.6	1.7	3.1	4.6	6.6	2.3
Severe Weather[d]	0.8	1.2	0.3	1.6	4.5	5.1	3.5	0.8	2.9	1.8	1.6	0.5	2.0	8.8	6.1	2.1	3.6	1.7
Construction Defects[e] or Material Failure[f]	16.0	14.4	13.3	18.2	20.1	20.5	11.3	10.0	9.6	24.4	29.1	8.7	26.8	16.6	44.7	18.2	29.6	20.3
External Impact[g]	21.2	25.3	21.6	23.7	27.8	27.1	35.2	31.2	37.3	29.2	28.1	15.6	30.6	34.4	16.8	41.0	36.4	40.2
Miscellaneous & Unknown	9.0	8.2	5.8	5.8	4.2	4.0	9.0	11.2	9.1	19.4	7.1	54.2	7.4	3.6	1.1	18.3	3.1	5.9
TOTAL	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

[a] Source: Reference 12.

[b] Incorrect operation by carrier personnel, surge of electricity and surge of flow.

[c] Malfunction of control or relief equipment, malfunction of valve, pump failure, pump packing failure, and tank roof drain leaking.

[d] Heavy rains or floods, cold weather, lightning and landslides.

[e] Defective girth weld, failure of previously welded repairs, and defective weld.

[f] Defective pipe seam, failure in river crossing, ruptured or leaking gasket, threads stripped or broken, pipe failed due to buckling, ruptured or leaking seal, pipe coupling failure, defective pipe, stress crack and wrinkle bend split.

[g] Equipment rupturing line, rupture of previously damaged pipe, freight train derailment, vandalism, and explosives.

[h] Percent figures may not total 100% due to rounding off.

TYPING GUIDE SHEET

TABLE 19. NUMBER AND VOLUME OF SPILLS FOR FAILURES OF PETROLEUM PIPELINE SYSTEM COMPONENTS (IN PERCENT OF TOTAL)

Pipeline System Component	1971		1972		1973		1974		1975		1971-1975	
	Spills	Vol	Spills	Vol	Spills	Vol	Spills	Vol	Spills	Vol	Spills	Vol
Line pipe	90	90	79	79	81	78	81	72	75	84	81	80
Pumping station	4	3	10	3	8	3	5	4	10	4	8	3
Delivery point	1	6	1	1	2	1	2	10	2	1	2	2
Tank farm	3	5	8	17	8	19	11	30	12	10	8	13
Bulk plant											<1	<1
Crossover											<1	<1
Test or safety						2	2				<1	<1
Underground storage											<1	<1
Reception point		3					1				<1	<1

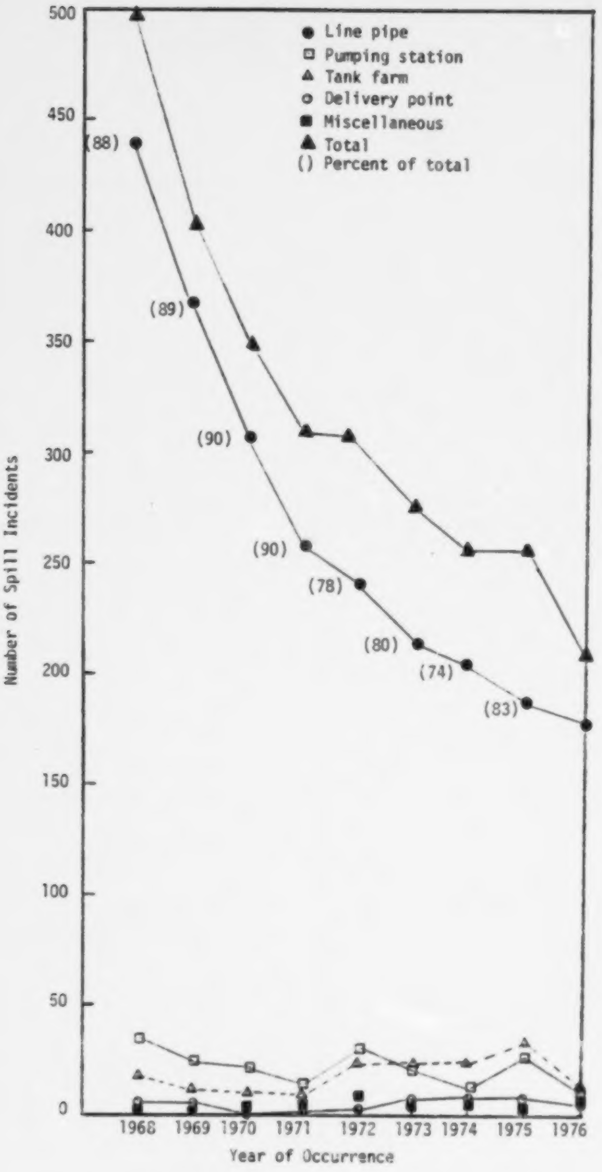


Figure 21. Number of incidents versus year of occurrence for carrier system components

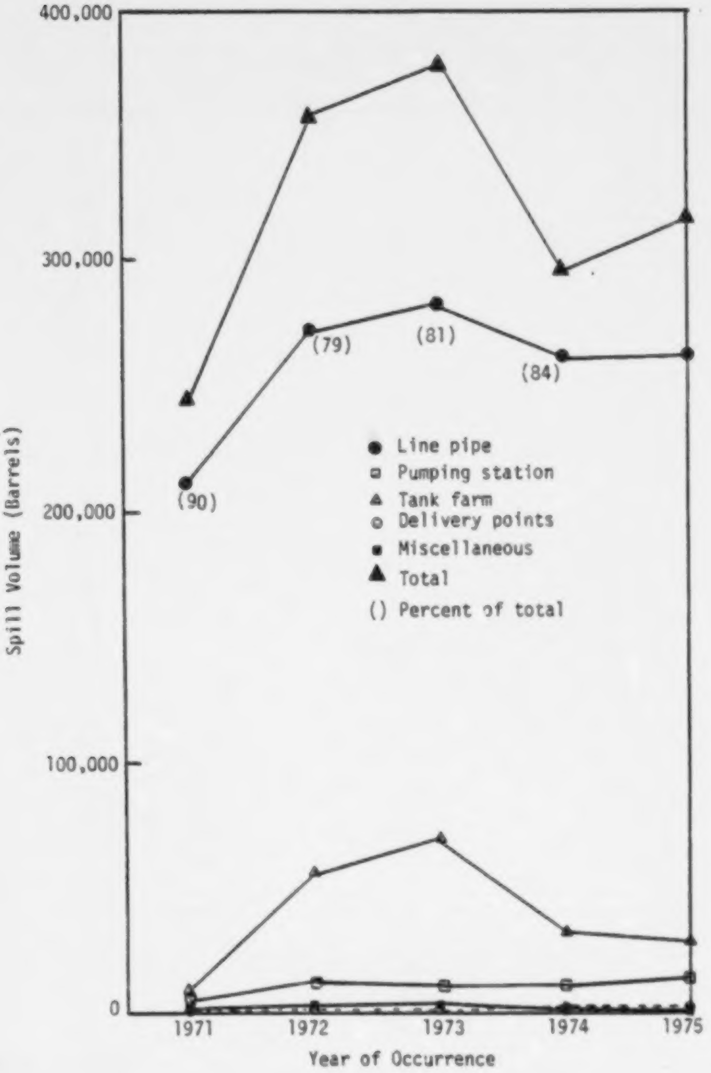


Figure 22. Volume of spill versus year of occurrence for carrier system components.

show that most spill incidents and volume can be attributed to failure in line pipe. During the 5-year period between 1971 and 1975, for example, line pipe accounted for over 80 percent of the total number and volume of spills. Figure 21 shows that the number of reported spills from line pipe decreased dramatically between 1968 and 1976 but remained relatively the same for other components. This rapid decrease in spill incidents of line pipe was not observed in spill statistics of petroleum pipeline systems from U.S. agencies for other areas or in statistics of gas leaks from gas transmission and gathering lines. In contrast, Figure 22 shows a slightly upward trend in the volume of spills from line pipe.

The tank farm was the only other component of the pipeline system where spills and spill volume were high. Between 1971 and 1975, 8 percent of the spills and 13 percent of the volume occurred at tank farms. There was a slightly upward trend in the number of incidents and no consistent trend in the volume of spills over this 5-year period.

Other major petroleum pipeline system components, including the pumping station, delivery point, bulk plant, crossover, underground storage and reception point, accounted for less than 7 percent of the spill volume and 11 percent of the spill incidents. The reported number of incidents and volume of spills were relatively the same, year-by-year.

4.6.2.1.3 Cause of Pipeline System Failures

Spills of 50 barrels or more from the pipeline system are due to a variety of causes (see Appendix C and Table 20). Only five causes, however, occurred more often than 2 percent of the time. These five causes, which accounted for over 78 percent of the spills and 66 percent of the volume from 1968 through 1976 (Table 22), are:

(1) Equipment rupturing the line - 15 percent spills, 24 percent volume

(2) Incorrect operation - 8 percent spills, 12 percent volume

(3) External corrosion - 29 percent spills, 12 percent volume

(4) Internal corrosion - 8 percent spills, 5 percent volume

(5) Defective pipe seam - 8 percent spills, 12 percent volume.

Variations in the number and volume of spills for these causes from year-to-year are illustrated in Figures 23 and 24. For comparison purposes, causes of spills are grouped into four main categories, i.e., outside forces, corrosion, material or construction defect and other causes.

Corrosion (internal and external) was the major cause of spills, accounting for an average of 37 percent of spill incidents and 16 percent of the spill volume between 1968 and 1976. However, corrosion has not been the major cause of spills since 1974 on a year-by-year basis. Spills caused by external corrosion decreased dramatically over this 9-year period (Figure 23). There appears to be no reason that adequately explains the decrease.

TABLE 20. NUMBER AND VOLUME OF ALL SPILLAGE INCIDENTS (IN PERCENT) FOR ALL PIPELINE SYSTEM COMPONENTS, BY CAUSE REPORTED TO OPSO BETWEEN 1971 AND 1975

Causes	1968		1969		1970		1971		1972		1973		1974		1975		1976		1968-1976	
	Spills	Vol	Spills	Vol	Spills	Vol	Spills	Vol	Spills	Vol	Spills	Vol	Spills	Vol	Spills	Vol	Spills	Vol	Spills	Vol
I. Outside Forces																				
1. Equipment rupturing line	20	23	22	25	20	15	22	25	22	23	24	12	31	34	29	26	32	29	25	24
2. Incorrect operation by carrier personnel	2	29	3	4	4	5	7	9	7	13	6	17	11	7	9	8	10	16	8	12
II. Corrosion																				
3. External	43	16	38	21	43	9	33	12	24	11	26	9	20	7	11	7	20	12	29	12
4. Internal	5	2	4	2	9	3	7	5	8	11	5	3			22	12	5	1	8	5
III. Material or Construction Defect																				
5. Defective pipe seam	6	7	8	2	8	7	10	15	9	12	8	27	8	17	6	14	7	15	8	13
TOTAL I, II, III	76	87	75	54	74	39	79	66	70	70	64	68	70	65	77	72	74	73	78	66
IV. Other	24	13	25	46	26	61	21	34	30	30	36	32	30	35	23	28	26	28	22	34
TOTAL I, II, III, IV	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100

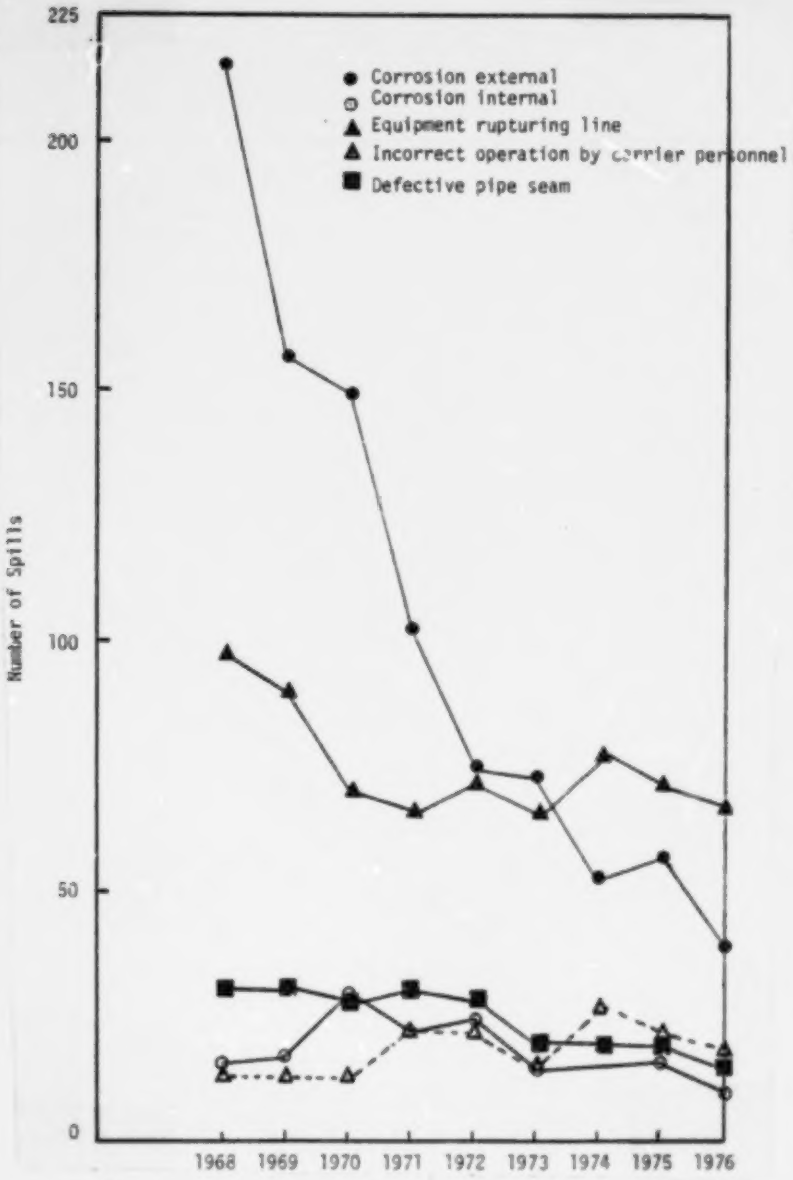


Figure 23. Number of spills versus year of occurrence by cause.

EPA Form 2330-6 (4-80)
(PREVIOUSLY C.H. EPA FORM 287)

TYPING GUIDE SHEET

BEGIN FIRST LINE OF TEXT HERE
CENTER OF PAGE
TOP OF IMAGE AREA
DROPPED HEAD: BEGIN SECTIONS HERE

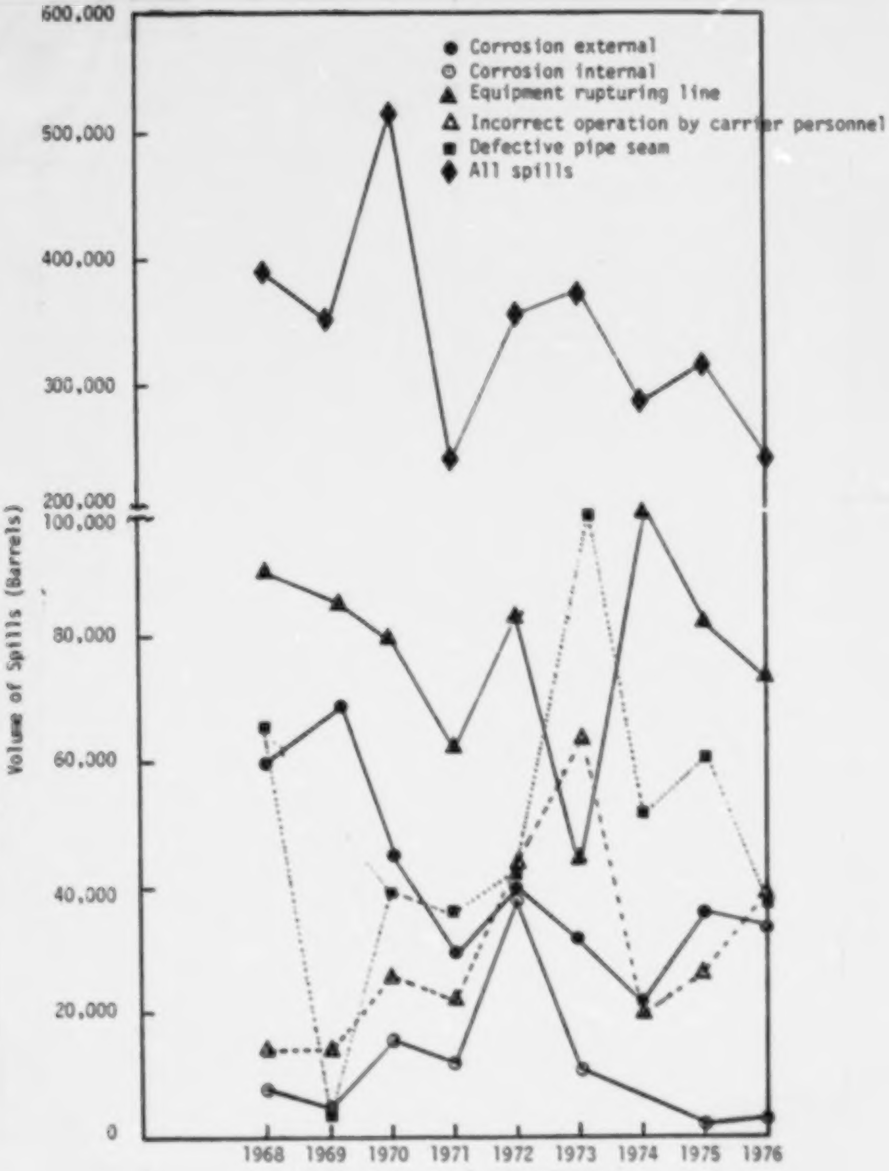


Figure 24. Volume of spill versus year of occurrence by cause.

BEGIN LAST LINE OF TEXT
TYPING GUIDE SHEET

Outside forces were the major causes of spills since 1974. There has been a slight decreasing trend in the number of incidents and a slight increasing trend in the volume of oil spilled over this 9-year period. Equipment rupturing the line and incorrect operation by carrier personnel were responsible for an average of 33 percent of the spills and 36 percent of the spill volume between 1968 and 1976. Defective pipe seams were the major cause of material failure or construction defects in the pipeline system. This cause accounted for an average of 8 percent of the spills and 13 percent of the spill volume between 1968 and 1974. The number of incidents has been fairly uniform and there has been no specific trend in the year-by-year spill volume.

Causes of Line Pipe Failure--Incidents and Spill Volume

Since line pipe accounts for most of the incidence of spills and spill volume in the petroleum pipeline system (see Section 4.6.2.1.2), it is treated separately. Statistics on the major causes of spills from line pipe are presented in Table 21 and Figure 25. An average of 82 percent of the total number of spills and 69 percent of the spill volume were due to only four main causes for the 4-year period between 1971 and 1974. These are:

(1) Outside Forces - 41 percent spills, 46 percent volume

  (a) Equipment rupturing the line - 31 percent spills, 26 percent volume

(2) Corrosion - 39 percent spills, 18 percent volume

  (a) External - 31 percent spills, 12 percent volume
  (b) Internal - 8 percent spills, 6 percent volume

(3) Material Failure or Construction Defect - 17 percent spills, 35 percent volume

  (d) Defective pipe seam - 12 percent spills, 25 percent volume

(4) Other - 3 percent spills, 1 percent volume.

Outside forces were the major cause of the incidence and volume of spills for line pipe. This cause accounted for 41 percent of the total incidents and 46 percent of the total spillage. Outside force incidents (total number of incidents and percent of all incidents) have been increasing steadily since 1971. Between 1971 and 1974, the number of incidents increased from 88 to 103 and the percentage of incidents increased from 34 to 53 percent. The spill volume, however, was relatively uniform over this period. Equipment rupturing the line was the predominant cause of spillage, accounting for 31 percent of the spills and 26 percent of the spill volume. Equipment rupturing the line and excavation equipment accounted for over 40 percent of the spill incidents and volume; these are the only two causes from outside forces that potentially can be reduced significantly by a spill prevention program.

TABLE 21. NUMBER, VOLUME AND PERCENTAGE OF ALL SPILLAGE INCIDENTS FOR LINE PIPE, BY CAUSE REPORTED TO OPSO BETWEEN 1971 and 1975

	1971				1972				1973				1974				1971-1974						
																	Total		Average % of Total		Average		
			% of Total				% of Total				% of Total				% of Total								
Cause	No. of Spills	Vol Barrels	Spills	Vol	No. of Spills	Vol Barrels	Spills	Vol	No. of Spills	Vol Barrels	Spills	Vol	No. of Spills	Vol Barrels	Spills	Vol	No. of Spills	Vol Barrels	Spills	Vol	No. of Spills	Vol Barrels	Spill Size Barrels
A. OUTSIDE FORCES																							
Equip. rupturing line	66	61,005	26	29	66	76,924	28	28	66	45,991	32	16	76	56,936	38	32	274	240,856	31	26	68	60,214	879
Incorrect operation by carrier personnel	2	5,211	1	2	1	4,712	0	2					1	170	0	0	4	10,093	0	1	1	2,523	2523
Fire or explosion	0	0	0	0	1	1,030	0	0	0	0	0	0	0	0	0	0	1	1,030	0	0	0.25	257	1030
Excavation equipment	4	10,825	2	5	6	33,157	3	12	9	19,881	4	7	8	13,168	4	7	27	77,031	3	7	7	19,258	2853
Flow control malfunction	1	4,030	0	2	1	1,242	0	0	2	5,555	1	2	2	225	1	0	6	11,052	1	1	1.5	2,763	1842
Flow control error	9	9,217	3	4	3	5,379	1	2	2	818	1	2	7	5,887	3	3	21	21,301	2	3	5	5,325	1014
Natural causes	6	14,060	2	7	9	8,007	4	3	11	21,686	5	8	11	13,913	5	8	37	57,666	4	7	9	14,416	1598
Tank overflow or operator error													1	100	0	0	1	100			0.25	25	100
TOTAL	88	104,348	34	49	84	130,415	36	48	90	93,931	42	35	103	90,399	53	50	365	419,093	41	46	91	104,773	1148
B. CORROSION																							
External	98	28,873	38	14	72	38,710	31	14	66	30,949	32	11	47	18,385	23	10	283	116,017	31	12	71	29,004	409
Internal	22	12,107	9	6	14	36,613	8	13	12	6,460	6	2	14	3,275	7	2	49	58,455	8	6	12	14,613	1192
TOTAL	120	40,980	47	20	91	75,323	39	27	78	37,409	38	13	61	21,660	30	12	332	175,372	39	18	83	43,843	528
C. DEFECTIVE PIPE																							
Seam	31	42,501	12	20	28	43,303	12	16	20	102,603	10	36	20	49,621	10	27	99	238,028	12	25	25	59,527	2404
Weld	10	13,818	4	7	10	6,472	4	2	8	27,215	4	10	8	11,159	4	6	36	58,664	4	6	9	14,666	1629
Rupture gasket, seal, packing and land	6	5,840	2	3	5	7,462	2	3	5	18,419	2	7	3	1,612	1	1	19	33,333	1	4	5	8,333	1754
TOTAL	47	62,159	18	30	43	57,237	18	21	33	148,237	16	53	31	63,392	15	34	154	331,025	17	35	38	82,756	2149
TOTAL (A,B,C)	255	207,487	99	98	218	262,395	93	96	201	279,577	96	99	195	175,451	98	96	869	924,910	97	99	217	231,227	1064
D. OTHER	3	5,213	1	2	17	9,287	7	4	3	3,156	4	1	7	5,116	2	4	27	22,722	3	1	7	5,680	841
TOTAL (A,B,C,D)	258	212,700	100	100	235	271,682	100	100	204	282,733	100	100	202	180,567	100	100	899	947,682	100	100	225	236,920	1054

[a] 1975: No. Spills - 188; Vol. (Barrels) - 261, 751; other statistics not available.

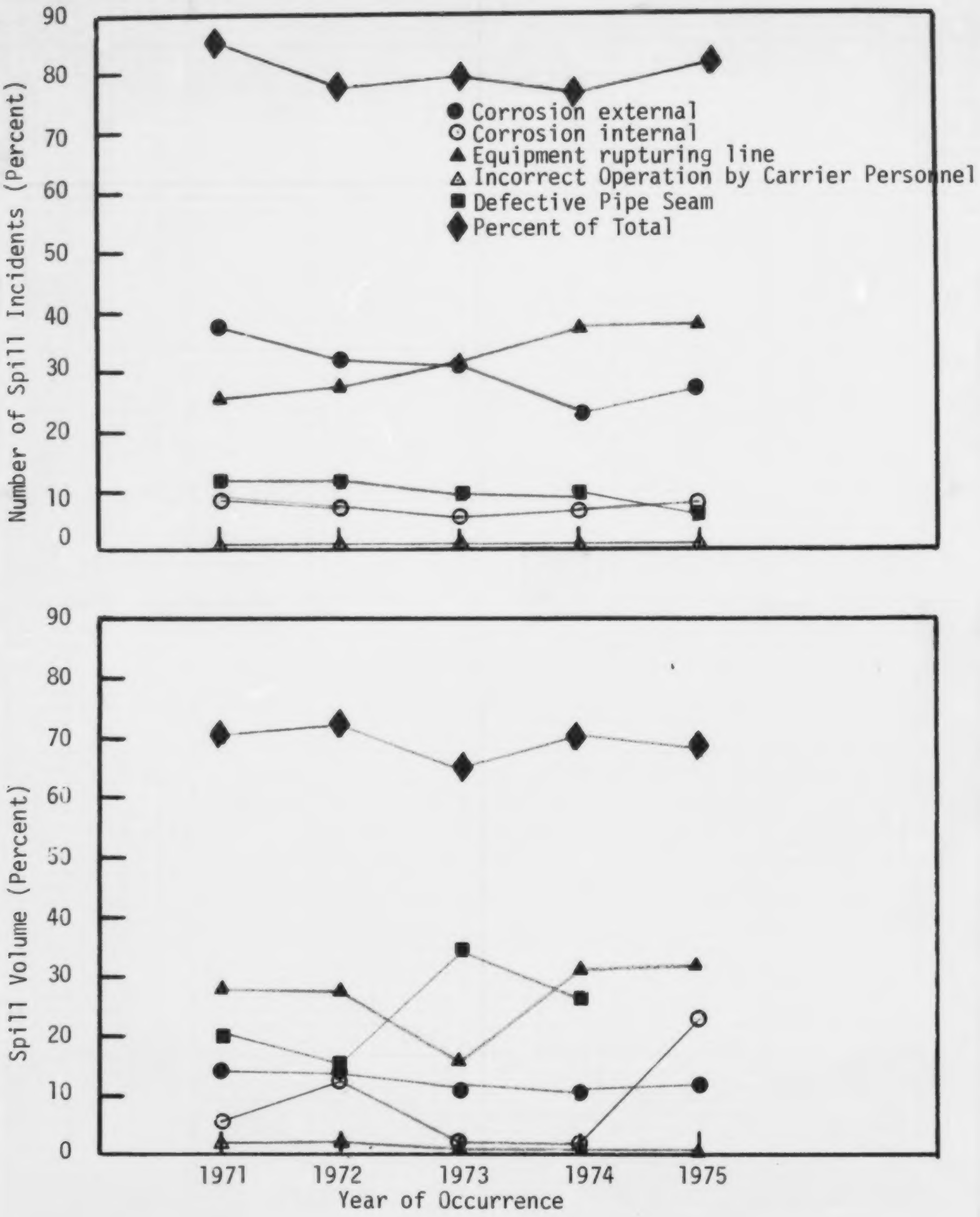


Figure 25. Percentage of number and volume of spills by cause for line pipe.

Table 21 shows that corrosion caused an average of 39 percent of the incident spills and only 18 percent of the spill volume between 1971 and 1974. Corrosion was the major cause of spills between 1971 and 1973. However, there has been a downward trend of the spill incidents and volume caused by corrosion since 1971. External corrosion was the major cause of corrosion failures and accounted for 31 percent of the total spills and 12 percent of the spill volume.

Defective pipe caused an average of 17 percent of the incidence of spills and 35 percent of the spill volume between 1971 and 1974. There has been a downward trend in the reported incidence of defective pipe since 1971; no trend is apparent for the spill volume. Defective pipe seams was the major cause of defective pipe failures and accounted for 12 percent of the total incidents of spills and 25 percent of the total spill volume.

Pipeline faults are caused mainly by corrosion and defective pipe. These accounted for an average of 56 percent of the total number of spills and 53 percent of the total spill volume between 1971 and 1974. The reported incidents of all pipeline faults shown in Table 19 have been decreasing since 1971. In 1971 there were 167 incidents whereas in 1974 there were only 92 incidents. There is no explanation based on pipeline construction, materials, or maintenance that adequately accounts for this trend. Pipeline faults potentially can be reduced by line pipe inspections and maintenance.

Outside force incidents by themselves are quite significant but are not faults in the pipeline or maintenance procedures. They usually involve human error and insufficient communication between pipeline operators and equipment operators. These incidents potentially can be reduced by a prevention program that improves communication and/or detects or prevents impacts from outside forces before damage to the pipeline occurs.

4.6.2.1.4 Factors Relating to Spills

Type of Fluid-Pipeline Systems

Data are given in Table 22 for crude and product spills and in Table 18 for all types of fluids from petroleum pipeline systems in the U.S. that were reported to OPSO between 1969 and 1976. Figures 26 and 27 illustrate the yearly variations in the volume spilled and number of incidents of crude, products and LPG. Gasoline, fuel oil, jet fuel, diesel fuel, condensate, kerosene and anhydrous ammonia are included in the data as petroleum products in Table 22 and Figure 25.

Reported total spill volume (Table 22) averaged 335,644 barrels for the 9-year period between 1968 and 1976. The average volume of products spilled was about 20 percent higher than crude or 1306 and 1085 barrels, respectively. For a more recent period, 1971 through 1975, the average spill volume was about the same. Reported total number of spills of crude and products (Table 22) averaged 289 between 1968 and 1976. Spill incidents

TABLE 22. SPILL VOLUME AND INCIDENTS FOR ACCIDENTS REPORTED TO OPSO BETWEEN 1968 AND 1976 FOR CRUDE AND PRODUCT PIPELINE SYSTEMS

		Spills [a]		
Year	Petroleum	Commodity (Barrels)	Number	Commodity Barrels/Spill
1968	Crude	222,257	322	
	Products	107,154	134	
	TOTAL	329,416	456	
1969	Crude	174,640	246	
	Products	89,905	109	
	TOTAL	264,545	355	
1970	Crude	383,160	216	
	Products	92,348	107	
	TOTAL	475,508	323	
1971	Crude	115,670	172	
	Products	89,410	97	
	TOTAL	205,170	269	
1972	Crude	233,690	180	
	Products	96,555	107	
	TOTAL	330,245	287	
1973	Crude	208,373	155	
	Products	119,418	113	
	TOTAL	327,791	268	
1974	Crude	168,738	166	
	Products	60,824	60	
	TOTAL	229,562	226	
1975	Crude	105,871	135	
	Products	108,324	94	
	TOTAL	214,195	229	
1976	Crude	96,059	123	
	Products	128,363	72	
	TOTAL	224,422	195	
1968-1976	Crude	1,856,659	1,715	
	Products	1,163,969	893	
	Avg Crude	206,295	190	1,085
	Avg Prod	129,329	99	1,306
	Avg Total	335,624	289	1,161
1971-1975	Crude	832,432	908	
	Products	474,531	471	
	Avg Crude	165,486	161	1,027
	Avg Prod	94,906	94	1,009
	Avg Total	260,392	256	1,017

[a] Note: LPG spills are not included in this table.

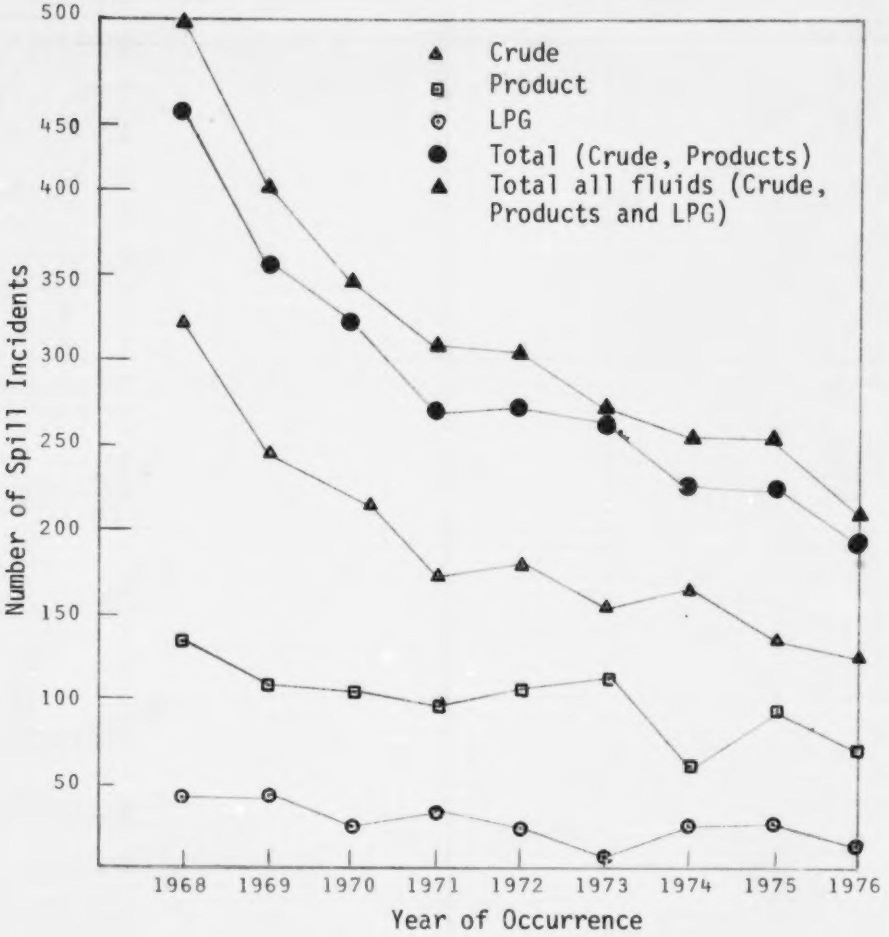


Figure 26. Number of incidents versus year of occurrence for type of fluid transported in pipeline system accidents reported to OPSO between 1968-1976.

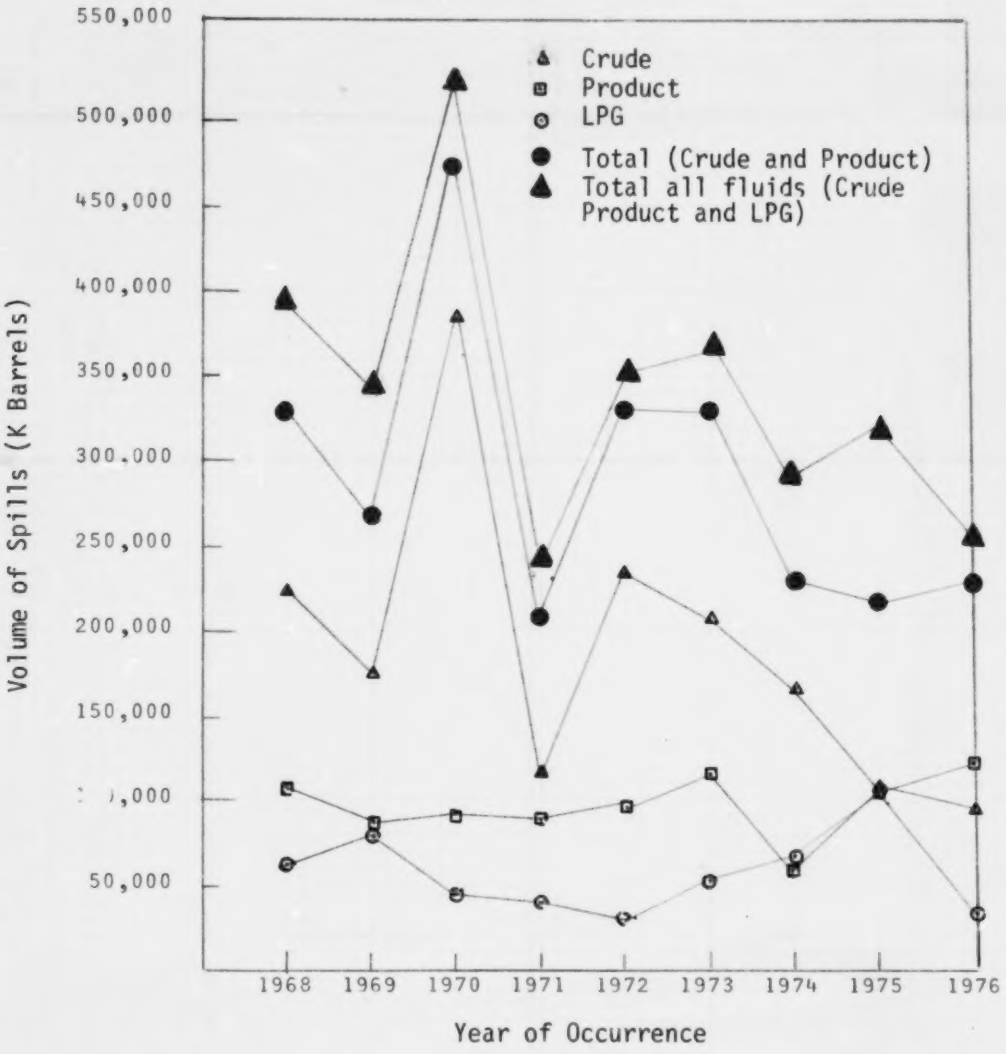


Figure 27. Volume of spills versus year of occurrence for type of fluid transported through pipeline system accidents reported to OPSO between 1968-1976.

BEGIN FIRST LINE OF TEXT HERE
CENTER OF PAGE
TOP OF IMAGE AREA
DROPPED HEAD, BEGIN SECTIONS HERE
TYPING GUIDE SHEET

averaged about 92 percent higher than products during this period, but only 71 percent higher for the 5-year period between 1971 and 1975. Figure 26 shows a steep declining trend in the yearly reported spill volume and incidents for crude. Trends for LPG and other product spills are different; a slight increasing trend is shown for the volume of spills and a slight downward trend in the number of incidents in Figure 27. There appears to be no conclusive explanation for the steep declining trend for spillage (incidents and volume) from crude pipeline systems.

Type of Fluid - Line Pipe

The incidents of line pipe spills of crude and product (including LPG) reported to OPSO for the 5-year period between 1971 and 1975 are given in Table 21 and illustrated in Figure 28. A slight decreasing trend is shown for crude while no specific trend is evident for product or LPG spills.

Annual distribution of spill frequencies and barrels lost from line pipe, including spills of less than 50 barrels, were estimated in Appendix D (LPG spills were not included in the analysis). Pertinent results are presented in Table 23. Annual incidents for spills of 50 barrels or more are estimated to be 86 percent greater for crude lines than for product lines. However, if all spill sizes are included, spill incidents from crude lines are estimated to be six times greater than for product lines. The larger number of spills from crude lines could be due to factors such as higher pipeline mileage, smaller diameter lines and age. These factors are considered in subsections that follow. Annual spill size for product line pipe is estimated to be 28 percent higher than for crude line pipe for spills of more than 50 barrels. This relationship of spill volume for crude and product lines is similar to that of the total petroleum pipeline system. If all spill sizes are included, annual spill size for product line pipe is estimated to be about three times greater than for crude line pipe.

Mileage - Pipeline System

A summary of spill incidents and volume for the pipeline mileage of the petroleum pipeline system during the 9-year period between 1968 and 1976 are tabulated in Table 24 and illustrated in Figures 29 and 30(A). Pipeline mileage data were obtained from BOM statistics presented in Table 8 and included the total mileage for crude and product transmission lines and crude gathering lines. Because spills from some of these pipelines are not required to be reported to OPSO, the actual mileage for calculation loss rates is somewhat less than used in these tables and figures. Thus the actual barrels spilled per mile and spill incidents per mile are higher than indicated.

Spill losses averaged 1.58 barrels per mile between the 9-year period from 1968 to 1976 and 1.44 barrels per mile between the 5-year period from 1971 to 1975. Spill incidents during these two periods averaged 1.45 and 1.26 spills per one thousand miles, respectively. A rapidly declining year-by-year trend for both spill incidents and spill volume per mile can be seen in Figures 29 and 30(A).

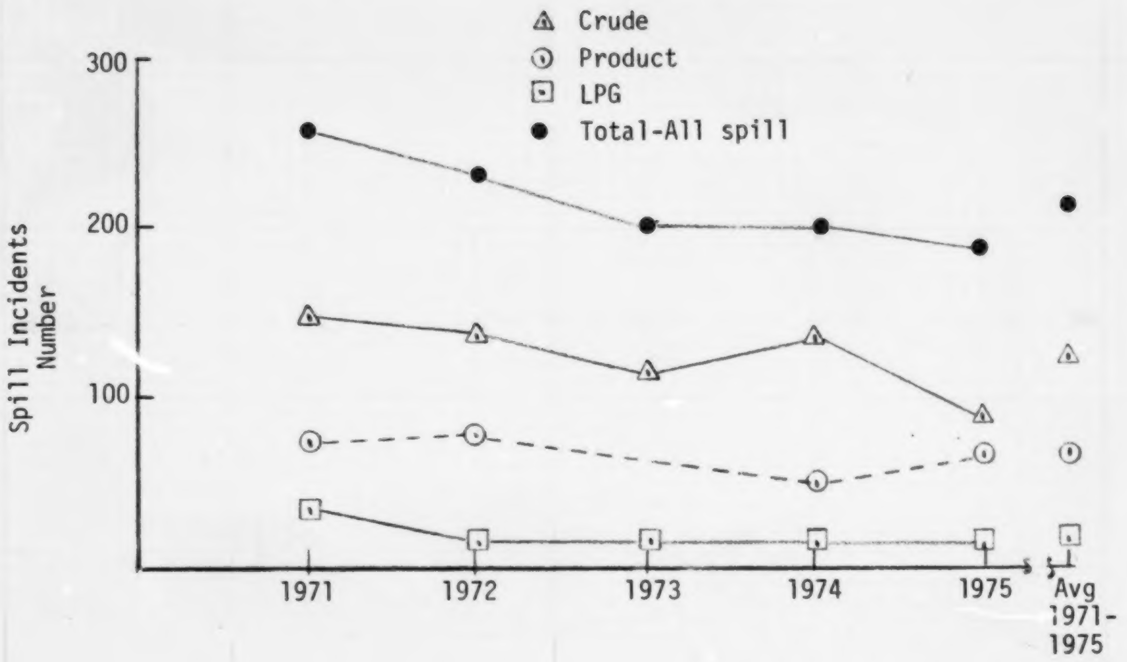


Figure 28. Number of incidents versus year of occurrence for type of fluid transported in line pipe, accidents reported to OPSO between 1971-1975.

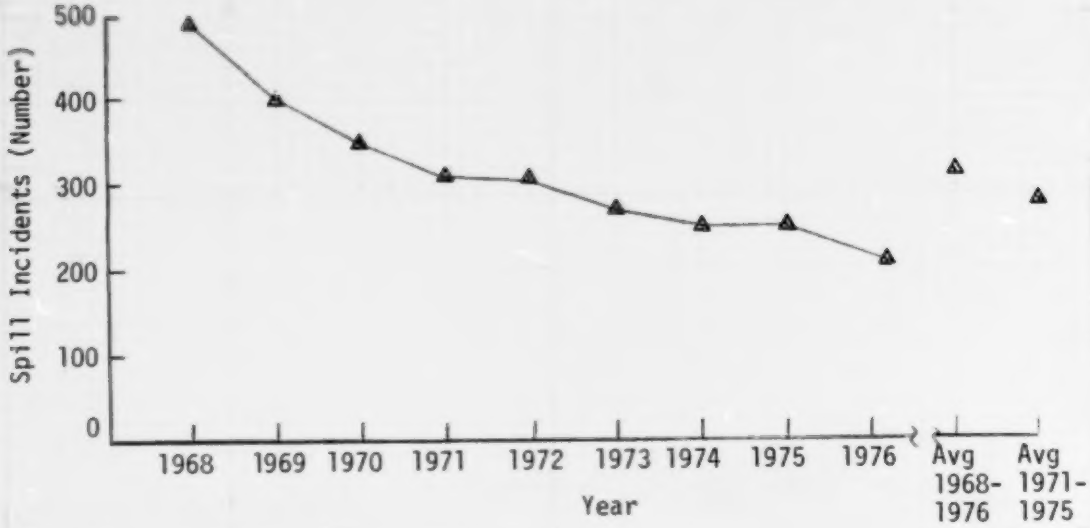
TABLE 23. STATISTICAL ESTIMATE OF ANNUAL DISTRIBUTION OF PETROLEUM[a] SPILL FREQUENCIES AND BARRELS LOST FROM LINE PIPE FOR CRUDE AND PRODUCT

	Frequency of Spills				Volume of Spills			
	Number		Percent		Barrels		Percent	
(Barrels)	Crude	Product	Crude	Product	Crude	Product	Crude	Product
0 - 50	300	7	70	9	2,796	194	2	0
50 - 100	33	7	8	9	2,391	541	2	1
100 - 200	28	11	7	14	3,969	1,588	3	2
200 - 400	22	13	5	17	6,233	3,832	5	4
400 - 800	16	13	4	17	9,262	7,595	7	9
800 - 1600	12	11	3	14	13,023	12,366	10	14
1600 - 25000	17	14	4	18	93,326	62,930	71	71
Total-All Spills	428	76	100	100	131,000	89,046	100	100
Total-Spills Greater than 50 Barrels	128	69	30	91	128,204	88,942	98	100

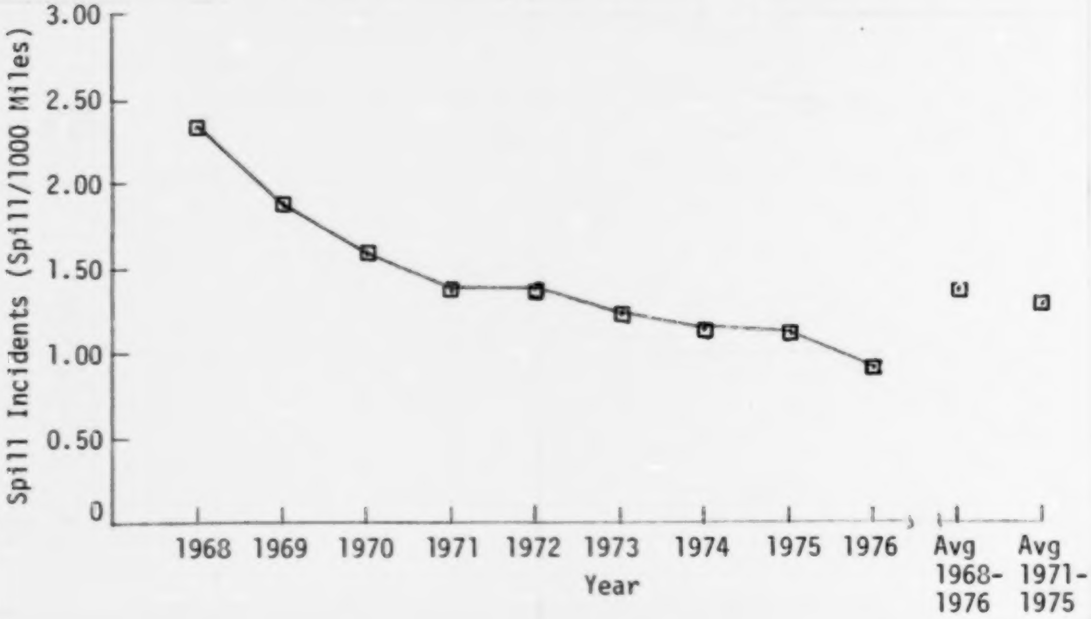
[a] LPG spills are not included in this table.

TABLE 24. SPILL DATA SUMMARY FOR PETROLEUM PIPELINE SYSTEMS TRANSPORTING LIQUIDS IN THE U.S. FOR ACCIDENTS REPORTED TO OPSO BETWEEN 1968-1976

Year	Through-put (Barrels x10^9)	Length (Miles)	Loss			Incidents	
			Barrels	% of Through-put	Barrels/Mile	Spills	Spills per 10^3 Miles
1968		209,478	392,588		1.87	490	2.3
1969		212,000	343,691		1.62	403	1.9
1970		215,000	521,849		2.43	347	1.6
1971	7.600	218,671	245,057	0.0032	1.12	308	1.4
1972	7.600	220,000	360,654	0.0047	1.64	309	1.4
1973	8.001	222,000	379,365	0.0047	1.71	273	1.2
1974	7.860	223,535	293,643	0.0037	1.31	256	1.1
1975	8.010	224,400	319,423	0.0040	1.42	255	1.1
1976	8.860	225,000	255,637	0.0029	1.13	209	0.9
1968-1976 Total		1,970,084	3,111,407			2,850	
Average		218,898	346,007		1.58	317	1.4
1971-1975 Total	39.07	1,108,606	1,598,142	0.020		1,401	1.2
Average	7.81	221,721	319,628	0.004	1.44	280	1.3

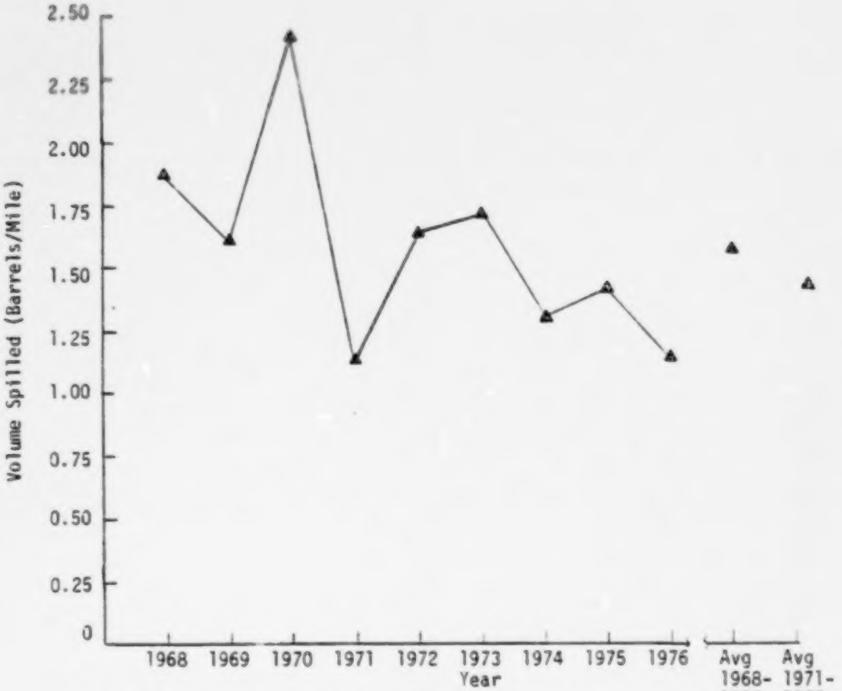


(A) SPILL INCIDENTS VERSUS YEAR

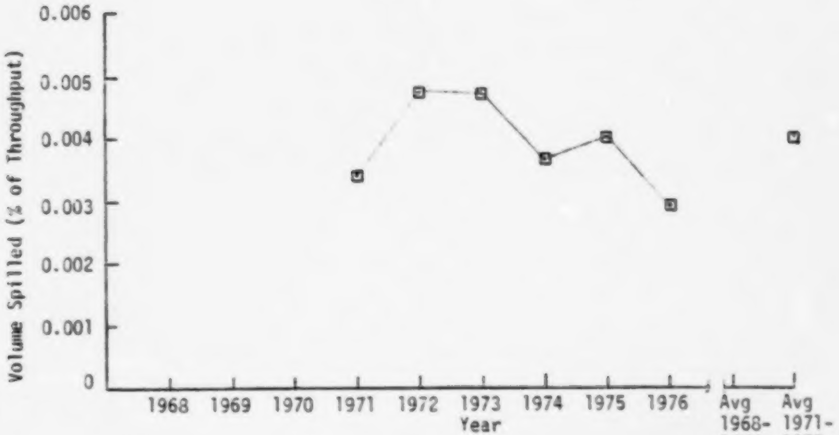


(B) SPILL INCIDENTS PER 1000 MILES VERSUS YEAR

Figure 29. Spill incidents and spills per 1000 miles versus year for pipeline system accidents reported to OPSO between 1968-1976.



(A) VOLUME SPILLED PER MILE VERSUS YEAR



(B) VOLUME SPILLED AS % OF THROUGHPUT VERSUS YEAR

Figure 30. Spill volume for mileage and throughput versus year for pipeline system accidents reported to OPSO between 1968-1976.

Mileage - Line Pipe

A summary of OPSO spill data for line pipe mileage is presented in Table 25 and illustrated in Figure 31 for the 5-year period between 1971 and 1975. Annual spill statistics for line pipe mileage are presented in Table 26. The latter statistics are based on the estimated (see Appendix D) line pipe spills and spill volume, including those of less than 50 barrels, presented in Table 23.

Table 25 shows that spill losses averaged 1.09 barrels per mile and spill incidents averaged 0.98 spills per one thousand miles during the 5-year period from 1971 to 1975. These values are only slightly lower (about 20 percent) than those for the entire petroleum pipeline system. This is expected, of course, because over 80 percent of the total spill incidents and volume are attributed to line pipe failures. Figure 31 shows a slight declining trend, year-by-year, of spill incidents per one thousand miles of line pipe while no specific trend is evident for barrels spilled per mile.

Estimated annual spill volume (Table 26) is 0.91 barrels per mile and spill incidents is 2.28 spills per one thousand miles. If LPG spills (approximately 10 percent of total) are added to this estimated annual spill volume, the resultant value would be about the same as the average value of 1.09 barrels per mile from actual OPSO statistics. This is expected even though the statistical estimate of annual spills includes spills of less than 50 barrels. This is because there appears to be no significant increase in the amount of spilled volume for spills of less than 50 barrels. Table 23 shows that below 50 barrels about 70 percent of the spills and only 2 percent of the spill volume are expected to occur for crude lines and about 9 percent of the spills and less than 1 percent of the spill volume are expected to occur for product lines.

Annual spill rate is estimated at 2.28 spills per mile for all petroleum line pipe. This value is much higher than the value computed for spills reported to OPSO. This increased rate is expected because of the large number of spills (Table 23) that are estimated to occur below 50 barrels. In addition, inclusion of spills not covered by OPSO regulations and estimation of unreported spills (to be discussed in later sections) will further increase this spill rate.

Crude spills (Table 26) are estimated to occur three times as often as product spills. A possible explanation for this is that crude lines are typically smaller in dimension (diameter and wall thickness) and somewhat older and thus have a higher frequency and a lower spill size. For product lines, the 0.97 spill rate per mile is about the same as the 0.98 value in Table 25 for all pipeline spills in excess of 50 barrels. This result is expected because product spills generally would be larger than crude spills because of larger pipeline diameter and thus are reported to OPSO. Also more product lines are under OPSO reporting regulations than crude lines.

TABLE 25. SPILL DATA SUMMARY FOR LINE PIPES TRANSPORTING LIQUIDS IN THE U.S. FOR ACCIDENTS REPORTED TO OPSO BETWEEN 1971-1975

			Loss			Incidents	
Year	Throughput (Barrels x10^9)	Length[a] (Miles)	Barrels	% of Throughput	Barrels/Mile	Spills	Spills per 10^3 Mile
1971	7.600	218,671	212,700	0.0028	0.97	258	1.18
1972	7.600	220,000	271,682	0.0036	1.23	235	1.07
1973	8.001	222,000	282,733	0.0035	1.27	204	0.92
1974	7.860	223,535	180,567	0.0023	0.80	202	0.90
1975	8.010	224,400	261,751	0.0032	1.16	188	0.84
1971-1975 Total	39.07	1,108,606	1,209,433			1,087	
Average	7.814	221,721	241,887	0.0031	1.09	217	0.98

[a] Mileage data obtained from Table 8.

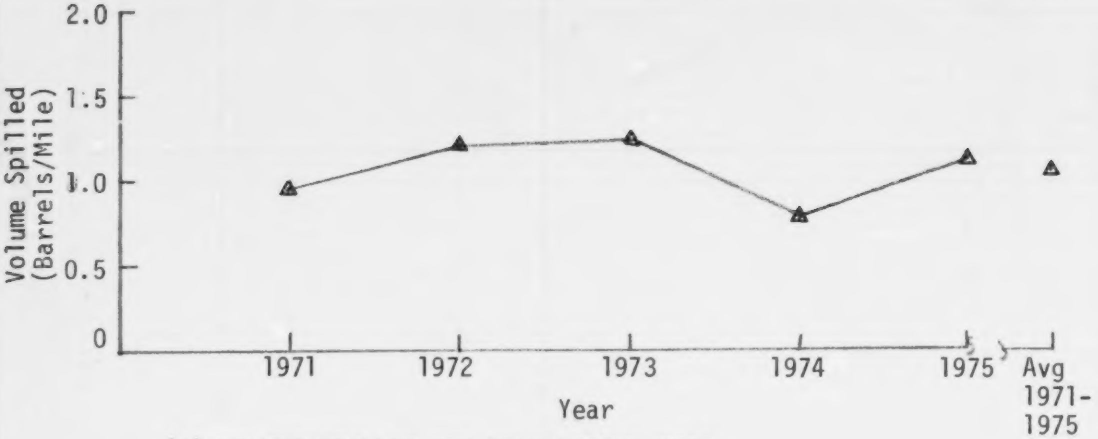
TABLE 26. ANNUAL SPILL[a] STATISTICS FOR LINE PIPES TRANSPORTING LIQUIDS IN THE U.S. FOR ALL SPILL SIZES

Commodity	Throughput (Barrels x10^9)	Length (Miles)	Barrels[b]	% of Throughput	Barrels/Mile	Spills[b]	Spills per 10^3 Miles
Petroleum	7.81[c]	221,000	220,046	0.0028	0.91	504	2.28
Crude	≈4.7	≈143,000	131,000	0.0028	0.91	428	2.99
Product	≈3.2	≈78,000	89,046	0.0028	1.14	76	0.97

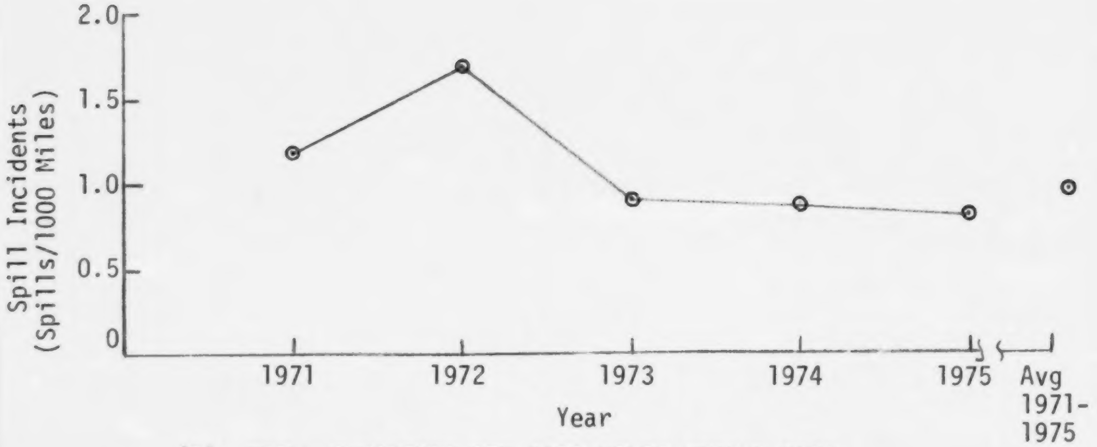
[a] Does not include LPG spills.

[b] Based on spill analysis in Appendix D.

[c] Based on average value between 1971 and 1975.



(A) VOLUME SPILLED PER MILE VERSUS YEAR



(B) SPILL INCIDENTS PER 1000 MILES VERSUS YEAR

Figure 31. Spill incidents per 1000 miles and spill volume per mile versus year for line pipe transporting liquids in the U.S. reported to OPSO between 1971 and 1975.

Throughput - Pipeline System

Spill statistics based on the throughput of petroleum pipeline systems are presented in Table 24 and illustrated in Figure 30(B). Throughput estimates are taken from BOM statistics (Table 5) and include domestic, foreign crude and natural gas liquids transported to the refinery input via pipelines, and petroleum products turned into pipelines.

Table 24 shows that spill losses for the period between 1971 and 1975 averaged 0.004 percent of total throughput. A slightly declining, year-by-year trend can be seen in Figure 30(B) for losses as a percent of throughput.

Throughput - Line Pipe

Line pipe spill data for throughput are presented in Tables 25 and 26. Losses (Table 25) for line pipe reported to OPSO during the 5-year period from 1971 through 1975 averaged 0.0031 percent of total throughput. This value was only slightly lower (about 20 percent) than for the entire petroleum system. This is expected because about 80 percent of the total spill volume is attributed to line pipe. There is no specific year-by-year trend for this data.

Estimated annual losses (Table 24) are 0.0028 percent of throughput. In comparison with the losses as reported to OPSO, this is a reasonable value considering that: (1) LPG spills, which account for about 10 percent of all spills, are not included in the estimated annual losses; (2) spills of less than 50 barrels are included in the estimated annual losses but are estimated to be less than 2 percent of the total volume; and (3) the estimates are based on spillage trends that indicate a declining trend (based on reported spills).

Diameter - Pipeline System

Spillage data for the petroleum pipeline system are broken down into two categories, i.e., those greater than and those less than 12 inches in diameter, in Figure 32. This was done because there was insufficient data, statistically, for an accurate breakdown for each individual size of pipeline greater than 12 inches in diameter. The spill rate for each category was estimated by dividing the total number of spills by the mileage existing at the beginning of 1974 and normalizing to one year. There were 190,331 miles of pipeline 12 inches in diameter or less and 34,296 miles of pipeline greater than 12 inches in diameter as of January 1, 1974. Table 27 shows the number of incidents and cause for these two categories for the 5-year period between 1971 and 1975.

The distribution of the sizes of the reported spills are plotted on log normal probability coordinates in Figure 32. For the larger diameter pipeline system, these data show the median spill size to be approximately 850 barrels. For pipeline systems less than 12 inches in diameter, the median spill size is 360 barrels. For the larger diameter pipeline systems, 8 percent of the reported spills exceeded 10,000 barrels.

TABLE 27. SPILL INCIDENTS OF PIPELINE SYSTEM FOR TWO PIPELINE DIAMETER CATEGORIES FOR ACCIDENTS REPORTED TO OPSO BETWEEN 1971-1975[a]

Cause	Pipelines 12 Inches and Less in Diameter		Pipelines Greater Than 12 Inches in Diameter
	Installed Before 1950 (Number of Incidents)	Installed After 1950 (Number of Incidents)	(Number of Incidents)
External Corrosion	297	50	9
Internal Corrosion	40	46	8
Line Ruptured by Excavation Equipment	142	128	28
Prior Damage by Excavation Equipment	6	18	3
Defective Pipe Seam	83	71	19
Defective Weld	22	11	7
Rupture of Gasket, Seal, etc.	23	56	2
Fire or Explosion	6	14	0
Flow Control Malfunction	3	11	0
Flow Control-Operator Error	23	12	0
Incorrect Operation by Carrier Personnel	2	11	0
Natural Disasters (Landslide, Flood, Windstorm, Freezing, etc.)	36	24	8
Unknown	55	67	8
TOTAL INCIDENTS	738	519	85

[a] Source: Reference 14.

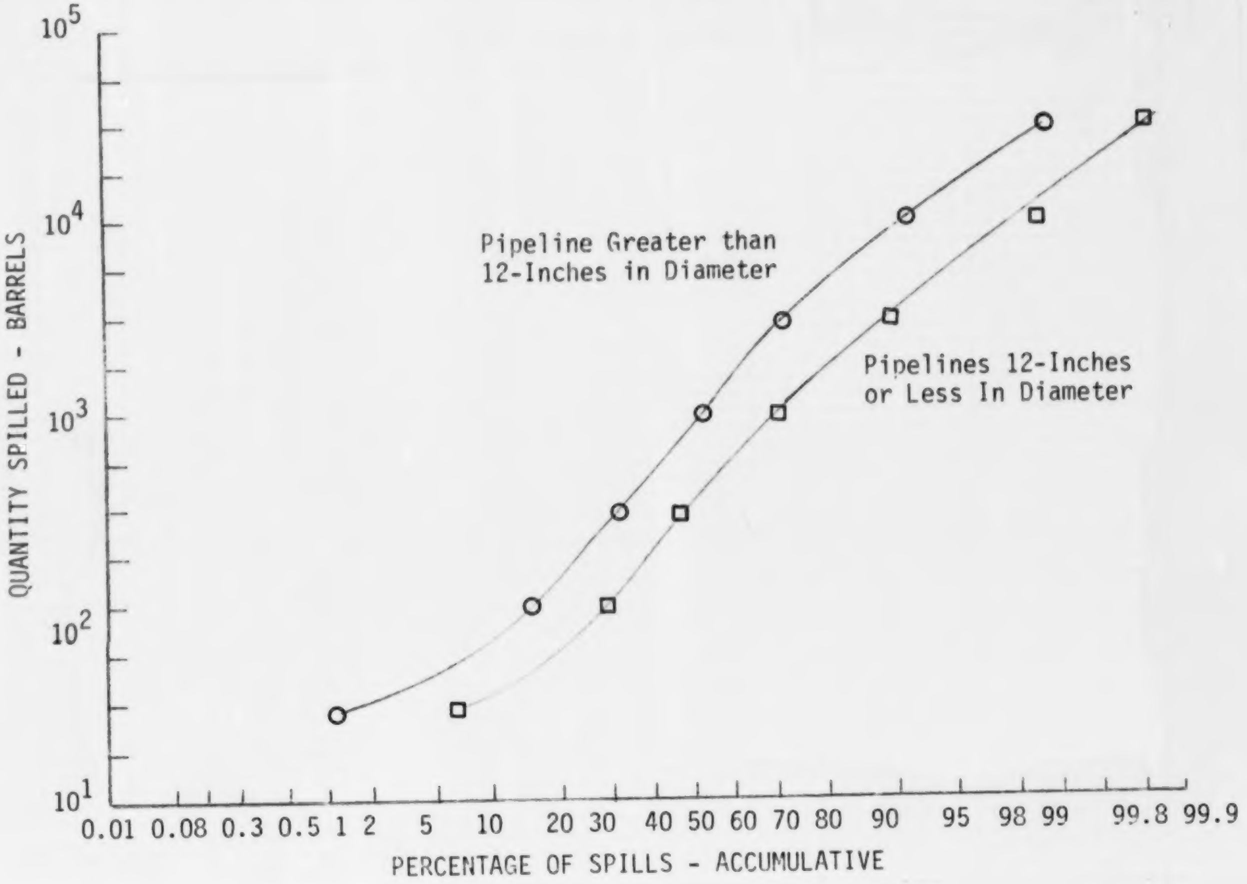


Figure 32. Size distribution of spills from U.S. terrestrial pipelines transporting liquids. (Source: Reference 14.)

Diameter - Line Pipe

Analysis was carried out according to individual sizes of line pipe. Statistics of spill incidents and volumes for pipeline diameters[a] reported to OPSO for line pipe were used.

The mean spill size (Table 28) increased from 569 barrels per spill for pipelines 4 inches or less in diameter to 6011 barrels for pipelines 30, 32 and 34 inches in diameter. Mean spill size increased with pipe diameter to the exponent 2.xx and is essentially proportional to the cross-sectional area of the pipe. These results are illustrated in Figures 33[b] and 34 where mean spill size is plotted for individual pipeline diameters. These results were particularly apparent for pipe diameters of 6, 8, 10 and 12 inches. Eighty-one percent of the spills and 78 percent of the spill volume were reported for these pipeline dimensions. The large number of incidents for these sizes was suitable, statistically, for accurate analysis.

The spill frequency (Figure 35) decreases rapidly as pipeline diameter increases and then levels off for pipelines greater than 14 inches in diameter. A peak rate of 2.14 spills/10^3 miles/year is initially reached for 4-inch diameter lines; then the rate levels off at about 0.5 spills/10^3 mile/year for lines that are larger than 14 inches in diameter. Note that when all gathering lines are included, the spill rate for 4-inch or less diameter lines is obviously too low and does not follow the general trend of spill frequencies and pipeline diameter. However, when gathering lines are excluded in the mileage, a more realistic trend occurs, but the value for the 4-inch or less diameter lines still appears slightly low.

Spill volume per mile (Figure 36) increases rapidly with pipeline diameter. A peak of 3.94 barrels/mile/year was reached for the 30, 32 and 34 inch diameter lines. Lowest spill volume, slightly above 1 barrel/mile/year, occurred for the small diameter lines. When all gathering lines are included in the pipeline mileage (Figure 36), the spill rate is obviously too low and does not follow the general trend. When gathering lines are excluded in the mileage, however, a more realistic trend occurs, but the value for 4-inch diameter lines or smaller still appears too high.

The outside force incidents on line pipe with diameter are shown in Table 29 for the four-year period between 1971 and 1974. Incidents caused by line pipe faults are shown in Table 30 for various pipe diameters. The frequency of spills caused by the equipment rupturing the line and corrosion (the major causes of damages by outside forces and line pipe faults) are illustrated in Figure 37 for the year 1971.

---

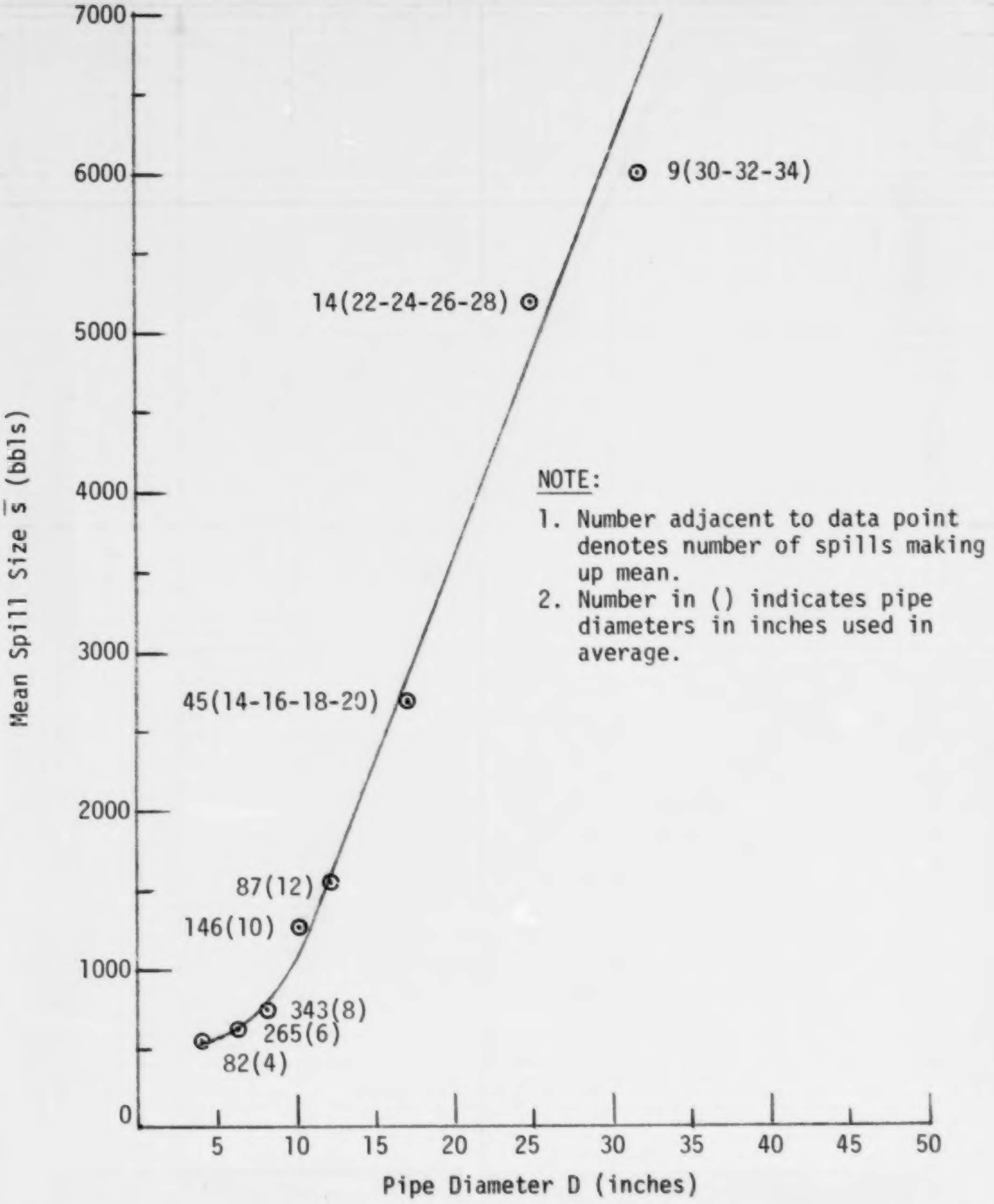
[a] Approximately 4 percent of the available data on reported spills did not include pipeline diameters; thus, relationships that use this particular statistic would be about 4 percent low. This, of course, does not affect relative values or trends.

[b] Combining more than one pipeline diameter appears to provide a clearer representation of the effect of spillage with pipe diameter.

TABLE 28. SUMMARY OF SPILL DATA FOR LINE PIPE DIAMETERS FOR LIQUID PIPELINE ACCIDENTS REPORTED TO OPSO BETWEEN 1971-1975

	1971-1975 Spills					All Pipelines				All Pipelines[a] Except Gathering			
Diameter (Inches)	Number of Spills	% of Total Spills	Volume Barrels	% of Total Volume	Mean Size Barrels	Miles	% of Total Miles	Spills/ 10^3 Miles/ Year	Barrels Spilled/ Mile/Year	Miles	% of Total Miles	Spills 10^3 Miles/ Year	Barrels Spilled/ Mile/Year
4 or less	82	8	46,685	4	569	59,891	27	0.26	0.24	7,637	5	2.14	1.22
6	265	26	164,749	15	622	36,664	16	1.4	0.9	26,454	17	2.14	1.24
8	343	33	255,652	24	745	52,892	24	1.28	0.96	47,753	31	1.42	1.07
10	146	14	185,142	17	1,268	22,592	10	1.3	1.64	21,652	14	1.32	1.71
12	87	8	132,240	12	1,520	19,512	9	0.9	1.36	18,886	12	0.92	1.4
14	6	<1	4,332	<1	722	3,402	2	0.36	0.26	3,384	2	0.36	0.26
16	20	2	21,043	2	1,052	7,664	3	0.52	0.54	7,622	5	0.52	0.54
18	5	<1	27,109	3	5,422	3,269	1	0.3	1.66	3,268	2	0.3	1.66
20	14	1	70,140	7	5,010	6,053	3	0.46	2.32	6,044	4	0.46	2.32
22-24	9	<1	20,445	2	2,771	4,703	2	0.38	0.87	4,699	3	0.18	0.87
26-28	5	<1	22,660	2	4,532	1,871	1	0.54	2.42	1,867	1	0.54	2.42
30-32-34	9	<1	54,098	5	6,011	2,750	1	0.66	3.94	2,750	2	0.66	3.94
36-up	4	<1	6,229	1	1,557	2,272	1	0.34	0.54	2,272	1	0.34	0.54
unknown	35	3	62,344	6	1,781								
Total	1,030		1,072,868		1,041	223,535		0.92	0.96	154,288		1.34	1.39

[a] Based on pipeline mileage in 1974.



NOTE:

1. Number adjacent to data point denotes number of spills making up mean.
2. Number in () indicates pipe diameters in inches used in average.

Figure 33. Mean spill size and line pipe diameter for line pipe accidents reported to OPSO, 1971-1975.

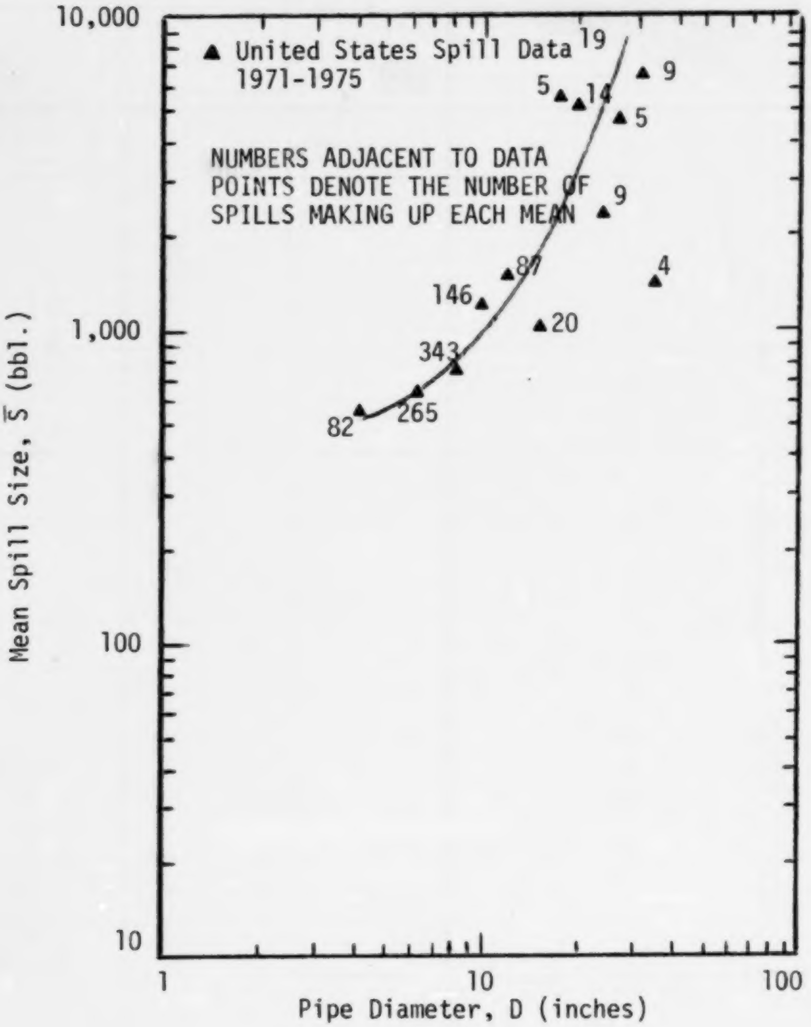


Figure 34. Mean spill versus line pipe diameter for line pipe accidents in the U.S. reported to OPSO between 1971-1975.

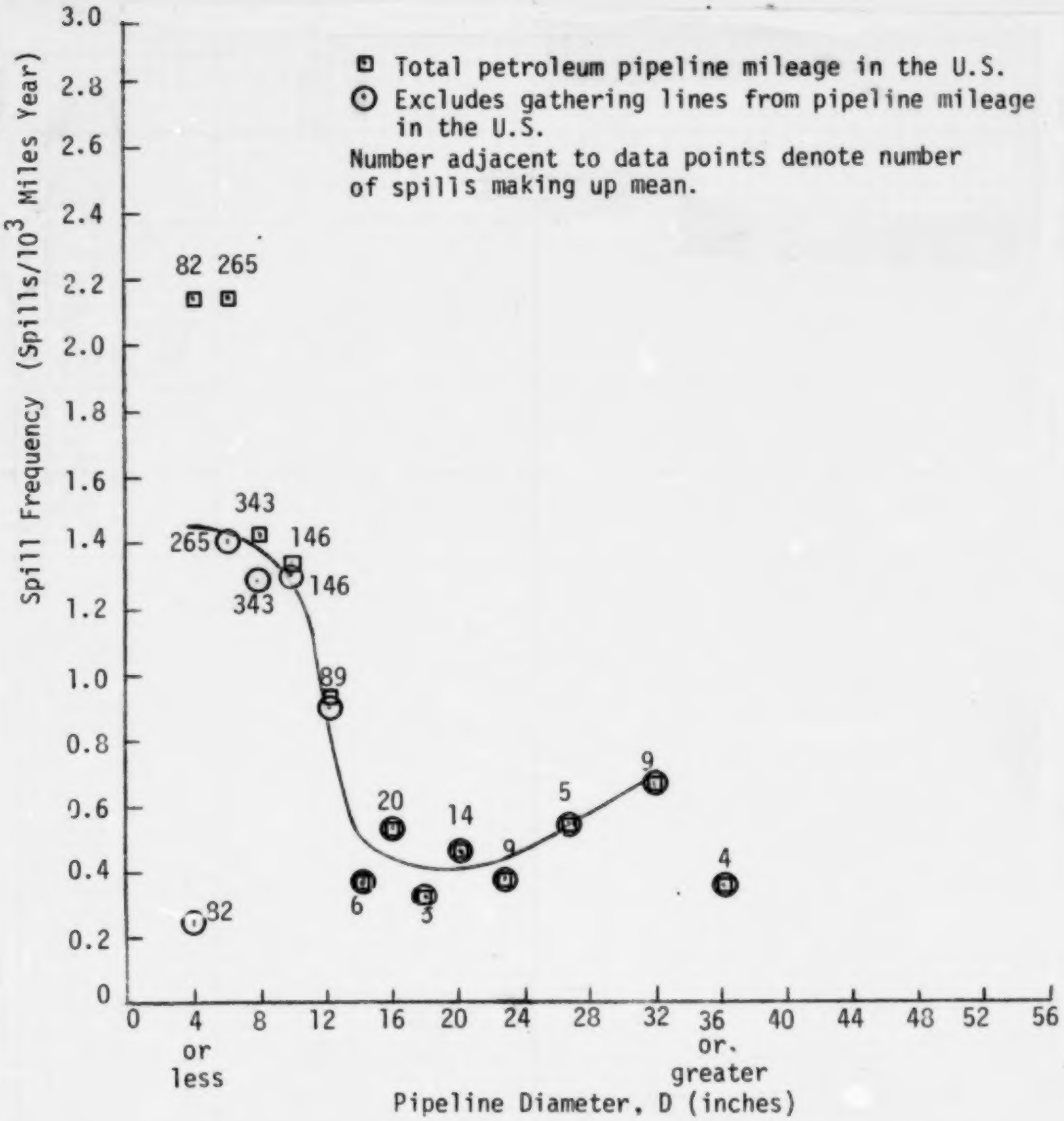


Figure 35. Frequency of spills for pipeline diameters and mileage for line pipe accidents in the U.S. reported to OPSO between 1971-1975.

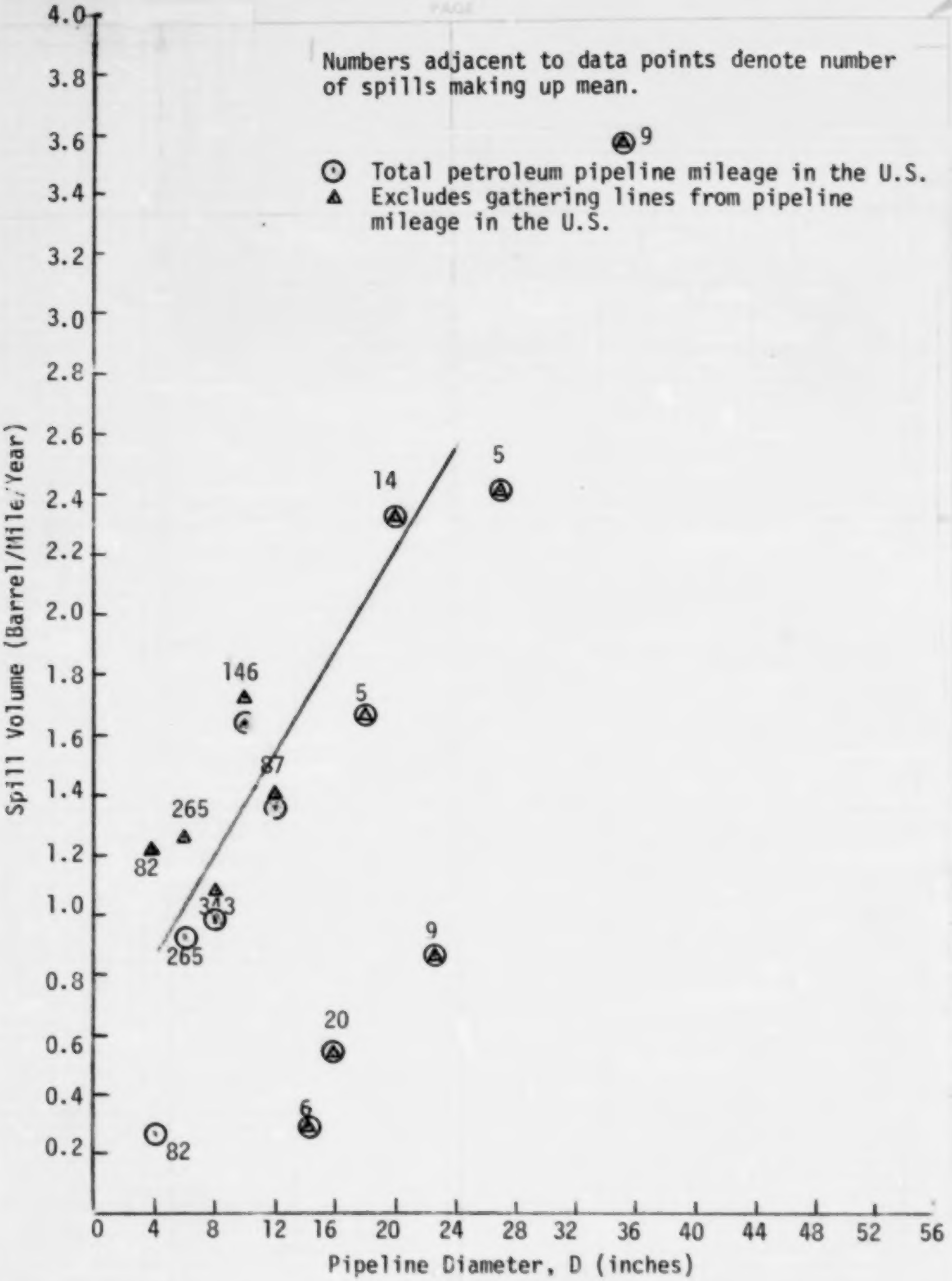


Figure 36. Spill volume for petroleum pipeline diameters of line pipe accidents reported in the U.S. to OPSO between 1971-1975.

TYPING GUIDE SHEET

TABLE 29. OUTSIDE FORCE INCIDENTS ON LINE PIPE REPORTED IN THE U.S. TO OPSO BETWEEN 1971-1974

LINE PIPE			Number of Incidents										
	Mileage		1971		1972		1973		1974		1971-1974		
Diameter (Inches)	All lines	All lines except gathering	Equipment Rupturing Line	Excavation Equipment	Equipment Rupturing Line	Excavation Equipment	Equipment Rupturing Line	Excavation Equipment	Equipment Rupturing Line	Excavation Equipment	Total Spills	Spills 10^3 mile-yr All Lines	Spills 10^3 mile-yr All Lines except gathering[a]
4 or less	59,899	7,637	4		5		5	1	17	1	33	0.13	1.07
6	36,664	26,454	19	1	15	1	13	1	18	3	71	0.48	0.67
8	52,892	47,753	22		23		23	4	14	2	88	0.41	0.46
10	22,592	21,652	11	1	7	2	5	1	12	1	40	0.44	0.46
12	19,512	18,886	3		7	2	8	1	7		28	0.35	0.37
14	3,402	3,384	1				1		1		3	0.22	0.22
16	7,664	7,622	3		3		4		3		13	0.40	0.40
18	3,269	3,268											
20	6,053	6,044	1	1	1		1		3		7	0.29	0.28
22-24	4,703	4,699				1					1	0.04	0.04
26-28	1,871	1,867											
30-32-34	2,750	2,750			3		1				4	0.40	0.40
36-up	2,272	2,272						1			1	0.10	0.10
unknown			2	1	2		5		1	1	12		
TOTALS	223,551	154,288	66	4	66	6	66	9	76	8	301	0.33	0.48

[a] 0.21 spills/10^3 mile-yr for line pipe greater than 12 inches in diameter.

TABLE 30. FAULT INCIDENTS FROM LINE PIPE REPORTED IN THE U.S. TO OPSO BETWEEN 1971-1974

Diameter (Inches)	Mileage		Number of Incidents											
			1971				1972				1973			
			Corrosion		Defective		Corrosion		Defective		Corrosion		Defective	
	All lines	All lines except gathering	External	Internal	Pipe Seam	Weld	External	Internal	Pipe Seam	Weld	External	Internal	Pipe Seam	Weld
4 or less	59,891	7,637	9				7	5	1	1	5	1	1	
6	36,664	26,454	29	7	3	1	16	9	2	1	22	8	3	
8	52,892	47,753	39	8	16	3	35	3	6	2	16	1	7	1
10	22,592	21,652	12	3	5		10	2	10	1	15	1	1	3
12	19,512	18,886	5	1	5	3	3		2	2	5		2	2
14	3,402	3,384	1						3					
16	7,664	7,622	1						1				1	
18	3,269	3,268												
20	6,053	6,044	1	1						1			1	1
22-24	4,703	4,699										1		
26-28	1,871	1,867							2				2	
30-32-34	2,750	2,750							1	1			1	
36-up	2,272	2,272			1									1
Unknown			1	2			1			1	3		1	
TOTAL	223,551	154,288	98	22	29	7	72	19	28	10	66	12	20	8

0.24 spills/10^3 miles-year for line pipe greater than 12 inches in diameter
0.22 spills/10^3 miles-year for line pipe greater than 14 inches in diameter

(continued)

TABLE 30 (continued)

Diameter (Inches)	Mileage		1971-1974 Corrosion			1971-1974 Defective Pipe & Weld			1971-1974 All Line Pipe Faults		
	All lines	All lines except gathering	Total Spills	Spills/10^3 mile-yr All lines	Spills/10^3 mile-yr Exc. gathering lines	Total Spills	Spills/ 10^3 mile-yr All lines	Spills/ 10^3 mile-yr Exc. gathering lines	Total Spills	Spills/ 10^3 mile-yr All Lines	Spills/ 10^3 mile-yr Exc. gathering lines *
4 or less	59,891	7,637	30	0.12	0.97	4	0.02	0.13	33	0.14	1.08
6	36,664	26,454	106	0.72	1.0	12	0.08	0.11	118	0.80	1.11
8	52,892	47,753	127	0.60	0.65	48	0.23	0.25	175	0.82	0.91
10	22,592	21,652	52	0.57	0.60	23	0.26	0.27	75	0.82	0.86
12	19,512	18,886	15	0.19	0.19	22	0.28	0.29	37	0.47	0.49
14	3,402	3,384	1	0.07	0.007	4	0.29	0.30	5	0.36	0.36
16	7,664	7,622	3	0.09	0.09	2	0.06	0.06	5	0.16	0.16
18	3,269	3,268	1	0.07	0.07				1	0.07	0.07
20	6,053	6,044	4	0.16	0.16	4	0.16	0.16	8	0.33	0.33
22-24	4,703	4,699	1	0.05	0.05	1	0.05	0.05	2	0.10	0.10
26-28	1,871	1,867				5	0.66	0.66	5	0.66	0.66
30-32-34	2,750	2,750				3	0.27	0.27	3	0.27	0.27
36-up	2,272	2,272	1	0.09	0.09	2	0.22	0.22	3	0.39	0.39
Unknown			9						13		
TOTAL	223,551	154,288	350	0.39	0.57	130	0.15	0.21	480	0.54	0.78

0.24 spills/10^3 miles-year for line pipe greater than 12 inches in diameter
0.22 spills/10^3 miles-year for line pipe greater than 14 inches in diameter

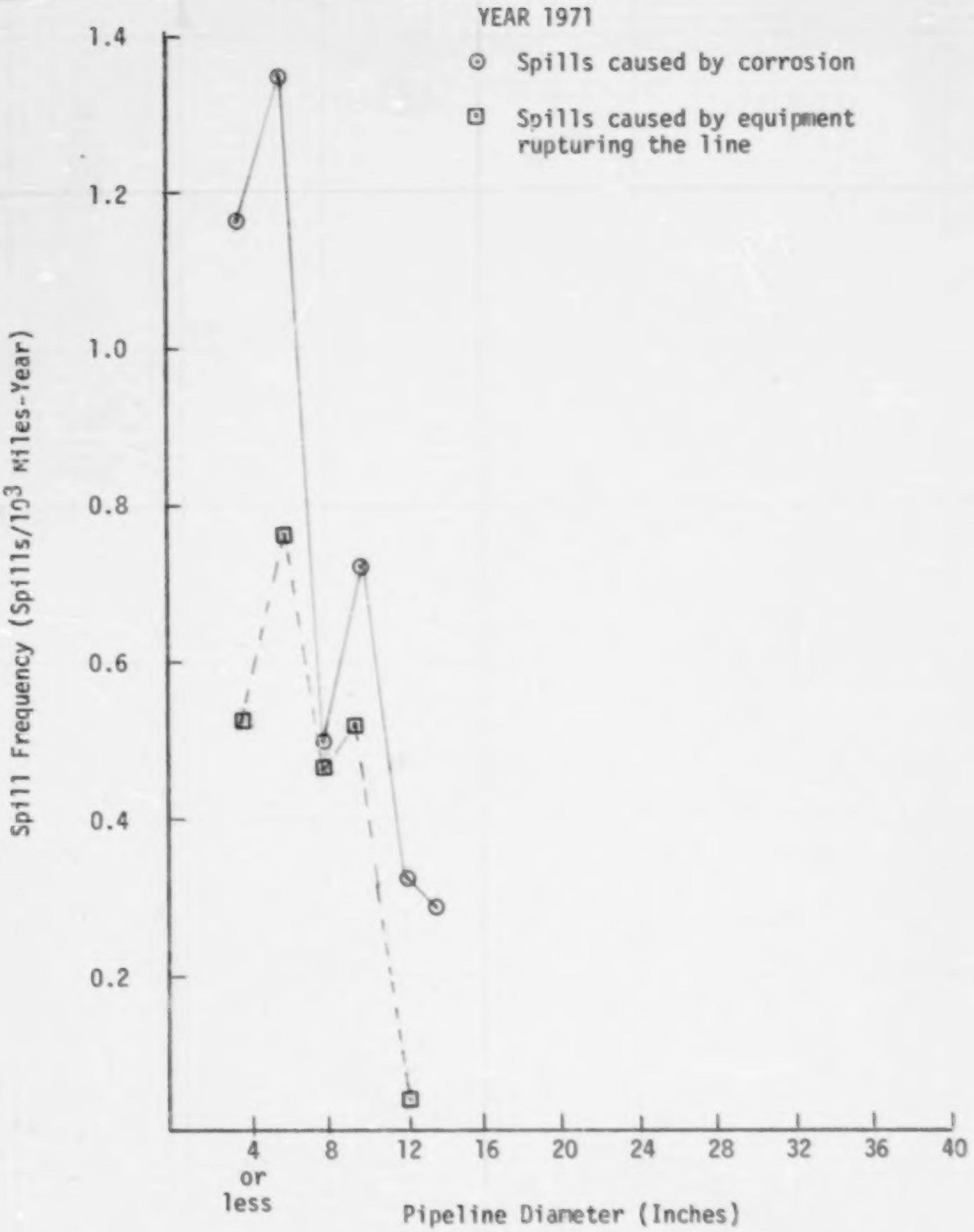


Figure 37. Diameter of line pipe and causes of spill incidents for accidents reported to OPSO in 1971.

Age - Pipeline System

Spill statistics for the frequency of spills as a function of age for the pipeline system are presented in Table 31 and illustrated in Figures 38 and 39 for the period between 1971 and 1975. The number of miles of pipeline installed in each of the time periods was taken from Table 12.

The number of incidents per 1000 miles of pipeline is illustrated in Figure 38. Results show that spill incidents are about the same, or about 0.8 spills per 1000 miles of line pipe, for pipeline systems installed after 1950. In contrast, spill rate increased rapidly as a function of pipeline age for lines built before 1950.

Table 27 shows that external corrosion caused over 40 percent of the spills for pipelines installed before 1950 while internal corrosion caused slightly less than 10 percent of the spills. Line rupture by excavation equipment and defective pipe seams caused the following: (a) over 38 percent of incidents for pipeline systems (12 inches in diameter or less) installed after 1950; (b) over 30 percent of the spills for pipeline systems installed before 1950; and (c) over 55 percent of spills for pipeline systems greater than 12 inches in diameter.

Age - Line Pipe

Spill statistics of the frequency of spills and spill volume as a function of age for the line pipe component of the pipeline system are presented in Table 32 and illustrated in Figure 40 for the 5-year period between 1971 and 1975. Additionally, major causes of spills for two typical years (1972 and 1974) are illustrated in Figure 41 for line pipe age.

Results in Table 32 and Figure 40 show that spill incidents per 1000 miles increase with line pipe age. Lines built before 1950, in particular before 1930, show a significantly high incidence of spills, whereas lines built after 1970 show a relatively low incidence of spills (about six times lower than for lines built before 1930).

Depth of Cover

Number of incidents as a function of depth of cover of the line are presented in Table 33. Mileage, geometry and age of line for each depth are not reportable and not included in the table. A discussion of this data is presented in Section 6.3.3.1.6.

Fatalities and Injuries

The number of fatalities and injuries resulting from petroleum incidents over the 9-year period from 1968 through 1976 are given in Table 34. Over this 9-year period the number of deaths averaged less than 4 and injuries less than 7. The number of fatalities and injuries occurring during the transportation of crude and products was about the same.

TABLE 31. SPILL INCIDENTS FOR PIPELINE SYSTEM AGE AND ESTIMATED[a] MILEAGE FOR ACCIDENTS REPORTED TO OPSO BETWEEN 1971-1975

	1971			1972			1973		
Year Installed	Number of Spills	Spill/ 10^3 Miles	% of Spills	Number of Spills	Spill/ 10^3 Miles	% of Spills	Number of Spills	Spill/ 10^3 Miles	% of Spills
Before 1938	53	4.51	17	47	4.2	15	39	3.5	14
1930 - 1939	53	4.0	17	26	1.9	8	34	2.5	13
1940 - 1949	52	2.1	17	39	1.6	13	44	2.0	18
1950 - 1959	60	0.9	20	75	1.1	24	59	0.9	22
1960 - 1969	50	0.7	16	67	0.9	22	51	0.7	19
1970 - Present	11	0.4	4	21	0.9	7	15	0.6	6
Unknown	28		9	34		11	25		9
TOTAL	307			309			272		

	1974			1975			1971-1975			
								Average		
Year Installed	Number of Spills	Spill/ 10^3 Miles	% of Spills	Number of Spills	Spill/ 10^3 Miles	% of Spills	Total Spills	% of Total	# of Spills	Spill/ 10^3 Miles
Before 1938	53	2.8	12	36	3.2	14	206	15	41	3.7
1930 - 1939	53	2.9	15	35	2.6	14	187	13	37	2.6
1940 - 1949	52	1.8	17	48	2.0	19	232	17	46	1.9
1950 - 1959	60	0.8	21	32	0.5	13	279	20	56	0.8
1960 - 1969	50	0.8	22	68	1.0	27	291	21	58	0.8
1970 - Present	11	0.9	9	26	1.1	10	95	7	19	9.7
Unknown	28		4	10		4	108	8	21	
TOTAL	307			255			1,398		280	

---

[a] Source: See Table 13.

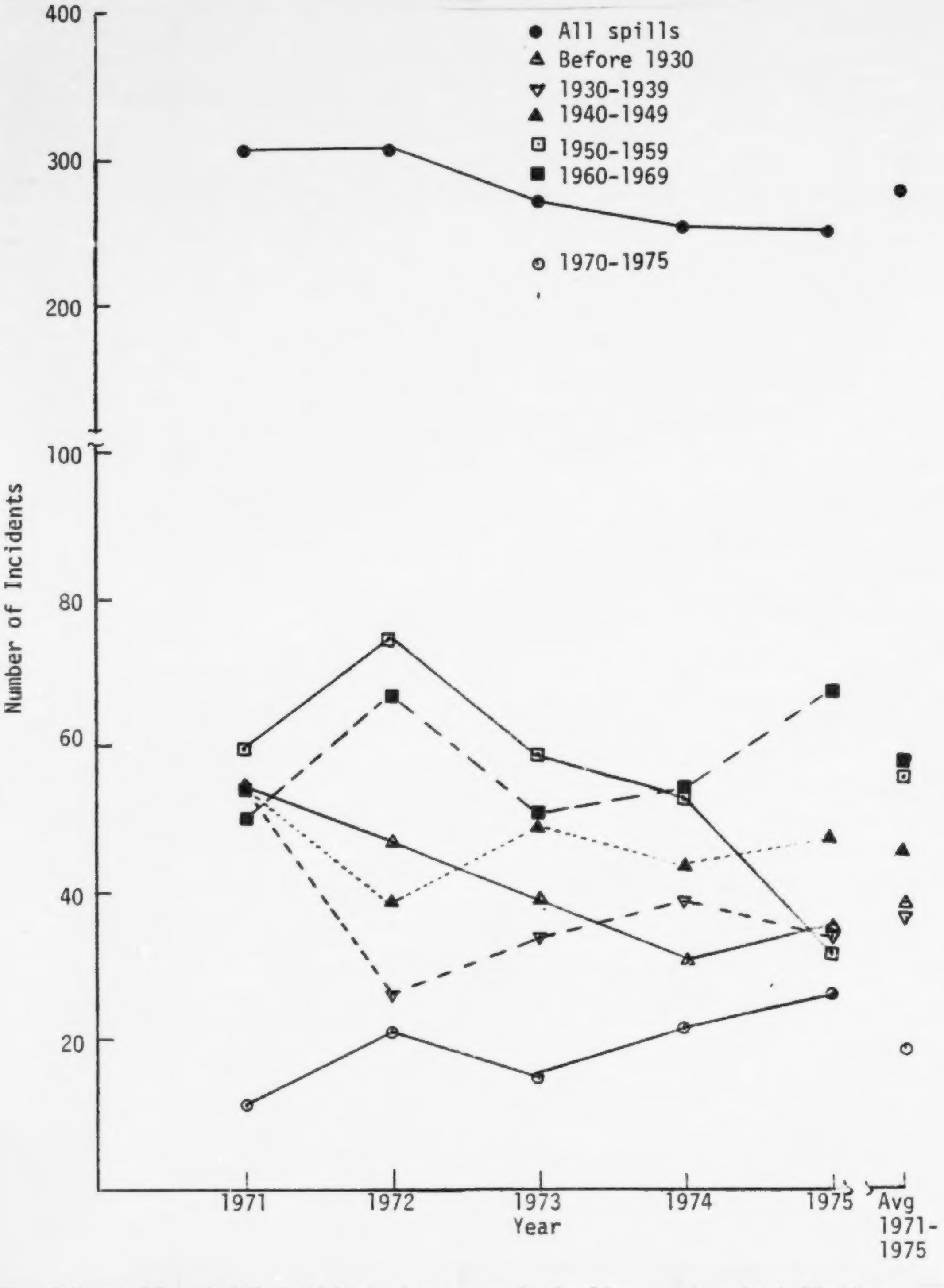


Figure 38. Spill incidents by year of pipeline system installation for accidents reported to OPSO between 1971-1975.

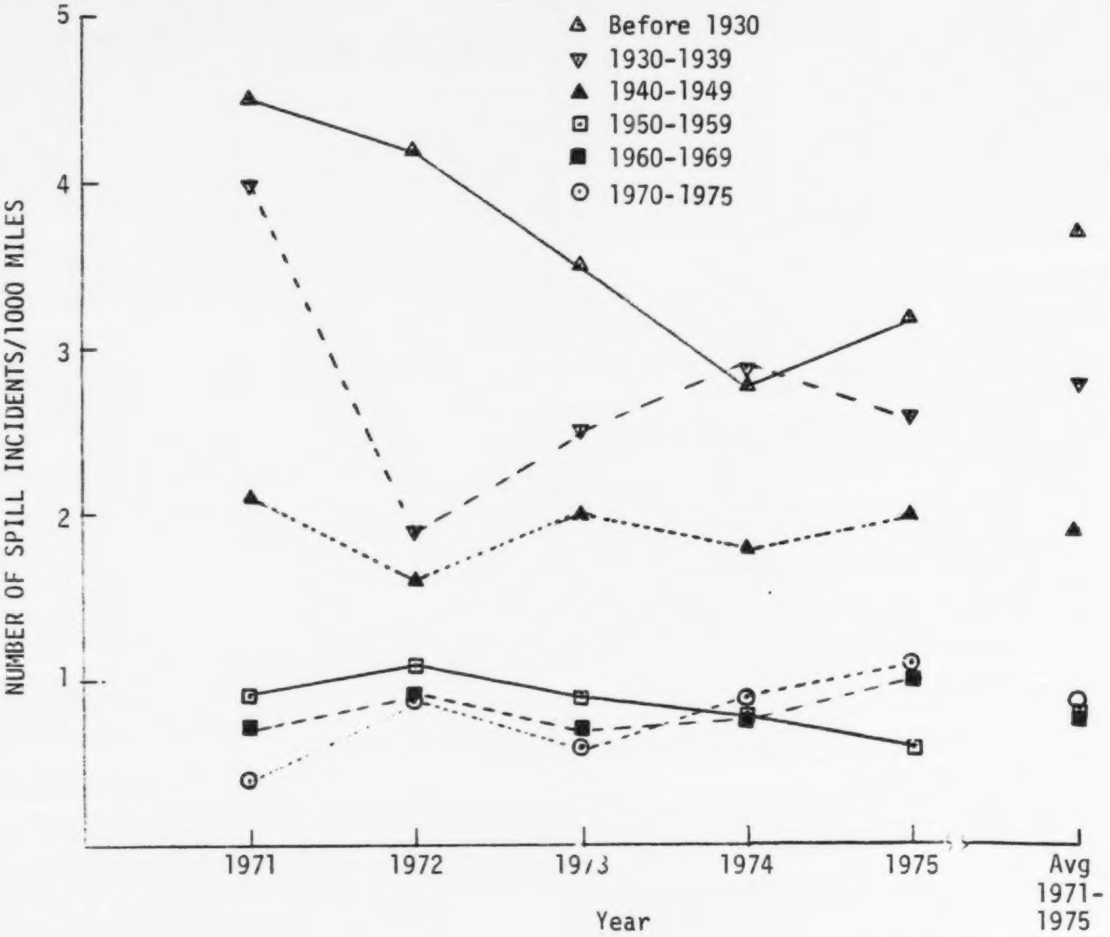


Figure 39. Pipeline system spill incidents per 1000 miles of pipeline by the year of pipeline system installation for accidents reported to OPSO between 1971-1975.

TABLE 32. SPILL INCIDENTS AND VOLUME FOR LINE PIPE AGE FOR ACCIDENTS REPORTED TO OPSO BETWEEN 1971 AND 1979

		1971				1972				1973			
Year Installed	Mileage[b]	Number of Spills	Spills / 10^3 Mi.	Volume of Spills (Bbls)	Bbls / 10^3 Mi.	Number of Spills	Spills / 10^3 Mi.	Volume of Spills (Bbls)	Bbls / 10^3 Mi.	Number of Spills	Spills / 10^3 Mi.	Volume of Spills (Bbls)	Bbls / 10^3 Mi.
Before 1930	11,172	51	4.56	26,432	2.36	42	3.75	41,705	3.73	36	3.22	134,942	12.07
1930 - 1939	13,412	50	3.72	30,514	2.27	25	1.86	15,846	1.18	25	1.86	15,544	1.15
1940 - 1949	24,588	47	1.91	36,556	1.48	32	1.3	35,764	1.45	41	1.66	40,894	1.66
1950 - 1959	69,295	47	0.67	54,637	0.78	65	0.93	99,350	1.43	44	0.63	118,341	1.70
1960 - 1969	71,531	39	0.54	53,414	0.74	38	0.53	69,236	0.96	32	0.44	47,896	0.66
1970 - 1979	53,000[a]	5	0.47 (10,618 Miles) [a]	4,366	0.41 (10,618 Miles)[a]	5	0.31 (15,927 Miles)[a]	6,003	0.37 (15,927 Miles)[a]	4	0.19 (21,236 Miles) [a]	5,345	0.25 (21,236 Miles)[a]
Unknown	8,941	20	2.23	6,781	0.75	27	3.01	12,578	1.46	21	2.34	7,271	0.81
TOTAL		259		212,700		234		280,482		203		370,233	

(continued)

---

[a] Estimated mileage after January 1, 1970 over indicated period (based on new pipeline mileage from 1971 through 1977).

[b] Estimated.

TABLE 32 (Continued)

Year Installed	Mileage[b]	1974				1975				1971 - 1975			
										Total		Average	
		Number of Spills	Spills / 10^3 Mi.	Volume of Spills (Bbls)	Bbls / 10^3 Mi.	Number of Spills	Spills / 10^3 Mi.	Volume of Spills (Bbls)	Bbls / 10^3 Mi.	Number of Spills	Volume of Spills (Bbls)	Spills / 10^3 Mi.	Bbls / 10^3 Mi.
Before 1930	11,172	25	2.23	19,827	1.77	31	2.77	7,436	0.66	185	230,342	3.31	4.12
1930 - 1939	13,412	35	2.60	15,424	1.15	31	2.31	20,225	1.50	166	97,553	2.47	1.45
1940 - 1949	24,588	37	1.50	40,488	1.64	42	1.70	28,742	1.16	199	182,444	1.61	1.48
1950 - 1959	69,295	43	0.62	40,311	0.58	27	0.38	60,810	0.87	226	373,449	0.66	1.07
1960 - 1969	71,531	41	0.57	106,071	1.48	44	0.61	106,071	1.48	194	382,688	0.54	0.87
1970 - 1979	53,000[a]	10	0.38 (26,545 Miles)[a]	32,586	1.23 (26,545 Miles)[a]	8	0.25 (31,854 Miles)[a]	32,586	1.02 (31,854 Miles)[a]	32	65,605	0.31 (21,200 Miles)[a]	0.62 (21,200 Miles)[a]
Unknown	8,941	8	0.89	1,894	0.21	3	0.33	2,579	0.28	79	31,103	1.76	0.69
TOTAL		199		256,601		186		258,449		1,081	1,378,465		

---

[a] Estimated mileage after January 1, 1970 over indicated period (based on new pipeline mileage from 1971 through 1977).

[b] Estimated.

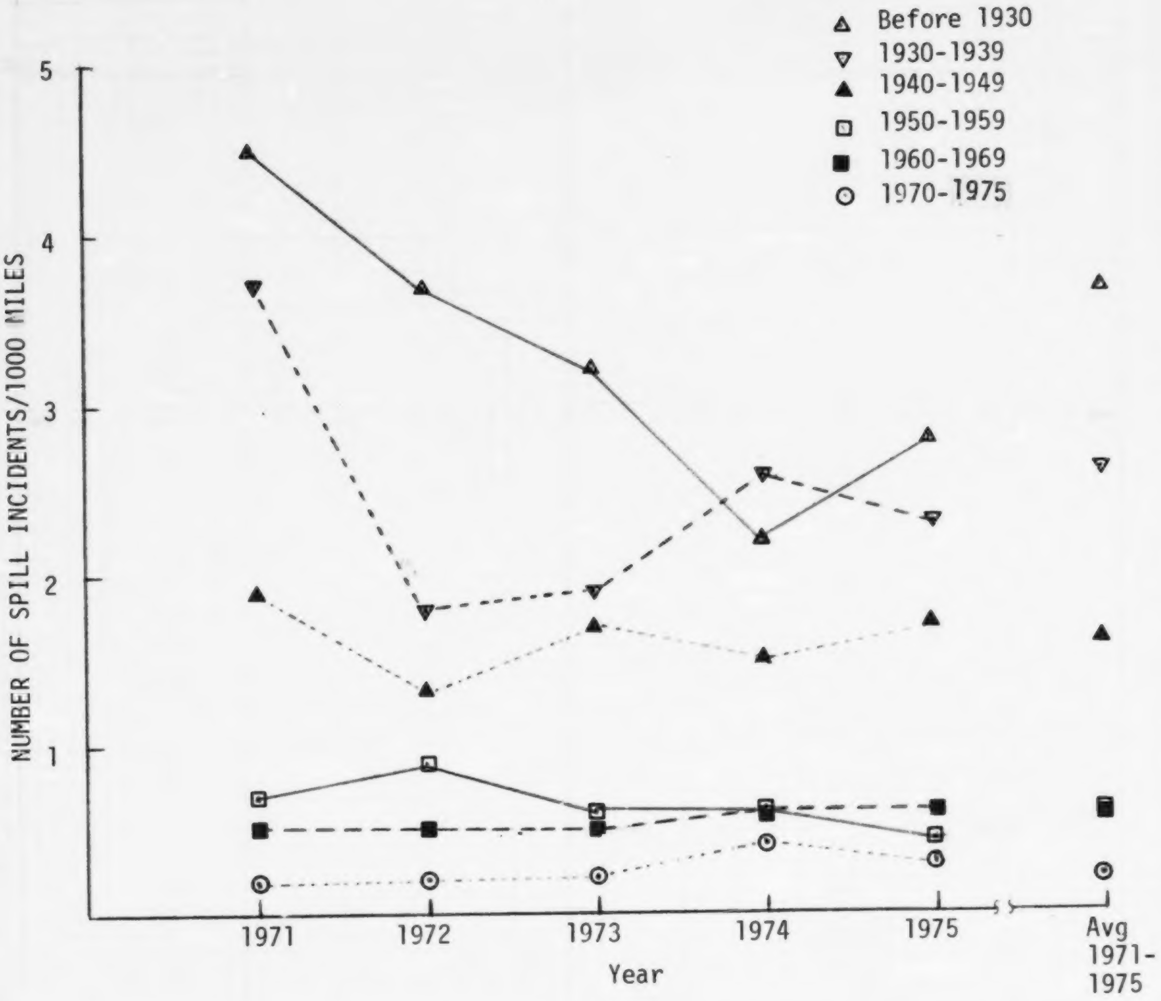


Figure 40. Line pipe spill incidents per 1000 miles of pipeline by the year of pipeline system installation for accidents reported to OPSO between 1971-1975.

TYPING GUIDE SHEET

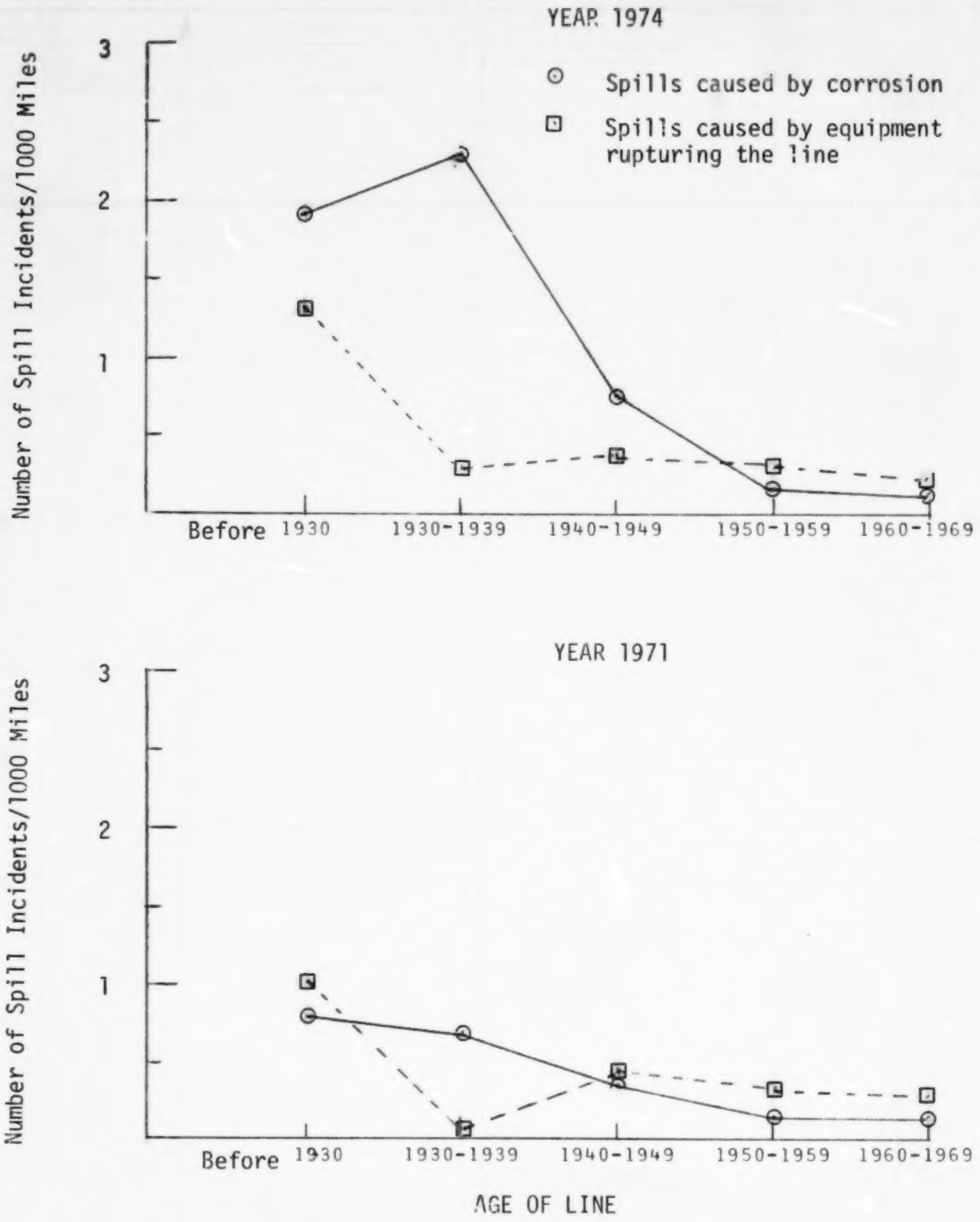


Figure 41. Age of line pipe and causes of spill incidents per 1000 miles of line pipe for accidents reported to OPSO in 1971 and 1974.

TABLE 33. NUMBER OF OUTSIDE FORCE INCIDENTS BY DEPTH OF COVER

Depth of Cover (inches)	Number of Incidents										Percent of Total
	1968	1969	1970	1971	1972	1973	1974	1975	1976	9-yr	
0	6	6	3	2	2	0	1	1	0	21	3.1
1 - 10	14	16	10	9	10	9	6	6	15	95	14.0
11 - 20	13	23	16	16	14	9	18	14	14	137	20.2
21 - 30	30	23	20	17	16	23	21	12	12	175	25.8
31 - 40	30	8	12	15	16	13	15	18	16	143	21.1
41 - up	--	12	9	7	10	8	10	18	5	79	11.6
Not applicable		2		1					1	4	0.6
Not reported	5				1	4	7	4	3	24	3.5
Total	98	90	70	67	69	66	78	73	67	678	

TABLE 34. FATALITIES AND INJURIES FOR PETROLEUM SYSTEM INCIDENTS REPORTED TO OPSO BETWEEN 1968 AND 1976

Year	Petroleum	Number of Spills	Incidents[a] Injuries	Deaths
1968	Crude	322	12	1
	Products	134	8	1
	TOTAL	456	20	2
1969	Crude	246	1	1
	Products	109	0	0
	TOTAL	355	1	1
1970	Crude	216	1	1
	Products	107	1	7
	TOTAL	323	2	8
1971	Crude	172	2	0
	Products	97	6	1
	TOTAL	269	8	1
1972	Crude	180	7	2
	Products	107	9	1
	TOTAL	287	16	3
1973	Crude	155	0	0
	Products	113	5	0
	TOTAL	268	5	0
1974	Crude	166	0	10
	Products	60	3	0
	TOTAL	226	3	10
1975	Crude	135	1	1
	Products	94	1	0
	TOTAL	229	2	1
1976	Crude	123	2	0
	Products	72	0	5
	TOTAL	195	2	5
1968-1976	Crude	1715	26	16
	Products	893	33	15
	Avg. Crude	190	3	2
	Avg. Product	99	4	2
	Avg. Total	289	7	4
1971-1975	Crude	808	10	13
	Product	471	24	2
	Avg. Crude	161	2	3
	Avg. Product	94	5	1
	Avg. Total	256	7	4

---

[a] LPG spills are not included in this table.

EPA Form 2350-1 (4-80)
(PREVIOUSLY LIN. EPA FORM 287)
TYPING GUIDE SHEET

Damage from Crude and Product

Damage figures from OPSO records include both property losses (dollars) and loss of commodity (barrels spilled). Table 35 summarizes these crude and product losses from petroleum pipeline system incidents for the 9-year period from 1968 through 1976. Products include gasoline, fuel oil, jet fuel, diesel fuel, condensate, kerosene and anhydrous ammonia. Figure 42 shows the variations in volume spilled, number of incidents, and property damage between 1968 and 1976 for crude and product transferred in the petroleum pipeline system. Table 30 shows that total property damage losses average $1,246,405 yearly over this 9-year period and the average loss for the 2608 spills was $430. Figure 42 shows a slight increasing trend of the property damage even though the number of incidents and spill volume showed a general declining trend.

Product spills were considerably more costly than crude spills. Results in Table 34 show that the average cost of property damage of an incident for the 9-year period from 1968 through 1976 was about 60 percent higher for products than for crude or $5786 and $3544, respectively. Between 1971 and 1975 the average cost of property damage for products was almost double that of crude, $8090 and $4181, respectively. This occurred even though the average spill size was about the same, 1009 and 1027 barrels, respectively. Similar property damage costs occurred for crude and product during these two periods, because pipeline systems incidents for crude were almost double those for product. For example, 1715 incidents for crude and 893 incidents for product were reported during the 9-year period from 1968 through 1976.

4.6.2.2 Loss Mechanism--Oil Spills in Outer Continental Shelf-USGS Statistics--

The U.S. Geological Survey is responsible for recording and investigating oil spills in the outer continental shelf. Since 1971, all spills in excess of 50 barrels have been recorded and a computer file is kept on all spills of one barrel or more. Spills of less than one barrel are assumed to be one-fourth barrel.

Total Spills--Volume, Throughput, Frequency

From January 1, 1971 to December 31, 1975, USGS[27,28] recorded oil spillage amounted to 51,421 barrels. Production during this period amounted to 1,810,996,199 barrels. The barrels spilled each year averaged 10,284 and barrels spilled per barrel of throughput was 0.0028 percent. Table 36 shows a summary of the number and volume of spills each year. Of the 5,857 spills recorded, 85.5 percent of the total spill volume was contributed by five spills; and 88.7 percent of the total spill volume was contributed by the 27 spills that were 50 barrels or more. Figure 43 shows the number and volume of 1 to 50 barrel spills for the years 1971 through 1975.

TABLE 35. DAMAGE FROM PETROLEUM PIPELINE SYSTEMS IN THE U.S. FOR INCIDENTS REPORTED TO OPSO BETWEEN 1968-1976

		Loss[a]				Spills[a]	
Year	Petroleum	Commodity (Barrels)	Property (Dollars)	Property Damage ($/Barrels)	Number	Property Damage ($/Spill)	Commodity Barrels/ Spill
1968	Crude	222,257	866,072	3.89	322		
	Products	107,154	481,437	4.49	134		
	TOTAL	329,416	1,347,509	4.09	456		
1969	Crude	174,640	1,176,260	6.73	246		
	Products	89,905	403,447	4.48	109		
	TOTAL	264,545	1,579,707	5.97	355		
1970	Crude	383,160	413,756	1.07	216		
	Products	92,348	120,035	1.299	107		
	TOTAL	475,508	533,791	1.12	323		
1971	Crude	115,670	117,938	1.02	172		
	Products	89,410	421,187	4.71	97		
	TOTAL	205,170	539,125	2.63	269		
1972	Crude	233,690	760,798	3.26	180		
	Products	96,555	1,508,464	15.62	107		
	TOTAL	330,245	2,269,262	6.87	287		
1973	Crude	208,373	411,080	1.97	155		
	Products	119,418	650,512	5.45	113		
	TOTAL	327,791	1,061,592	3.23	268		
1974	Crude	168,738	635,666	3.77	166		
	Products	60,824	155,150	2.55	60		
	TOTAL	329,562	790,816	2.39	226		
1975	Crude	105,871	1,441,764	13.62	135		
	Products	108,324	1,069,447	9.87	94		
	TOTAL	214,195	2,511,211	11.73	229		
1976	Crude	96,059	238,523	2.48	123		
	Products	128,363	346,129	2.67	72		
	TOTAL	224,422	584,652	2.605	195		
1968-1976	Crude	1,856,659	6,061,857	3.26	1715		
	Product	1,163,969	5,155,798	4.42	893		
	Avg Crude	206,295	673,539	3.26	190	3,544	1,085
	Avg Prod	129,329	572,866	4.42	99	5,786	1,306
	Avg Total	335,624	1,246,405	3.71	289	4,312	1,161
1971-1975	Crude	832,432	3,367,246	4.04	808		
	Product	474,531	3,804,760	8.01	471		
	Avg Crude	165,486	673,249	4.04	161	4,181	1,027
	Avg Prod	94,906	760,952	8.01	94	8,090	1,009
	Avg Total	260,392	1,434,001	5.50	256	5,600	1,017

[a] Note: LPG spills and losses are not included in this table.

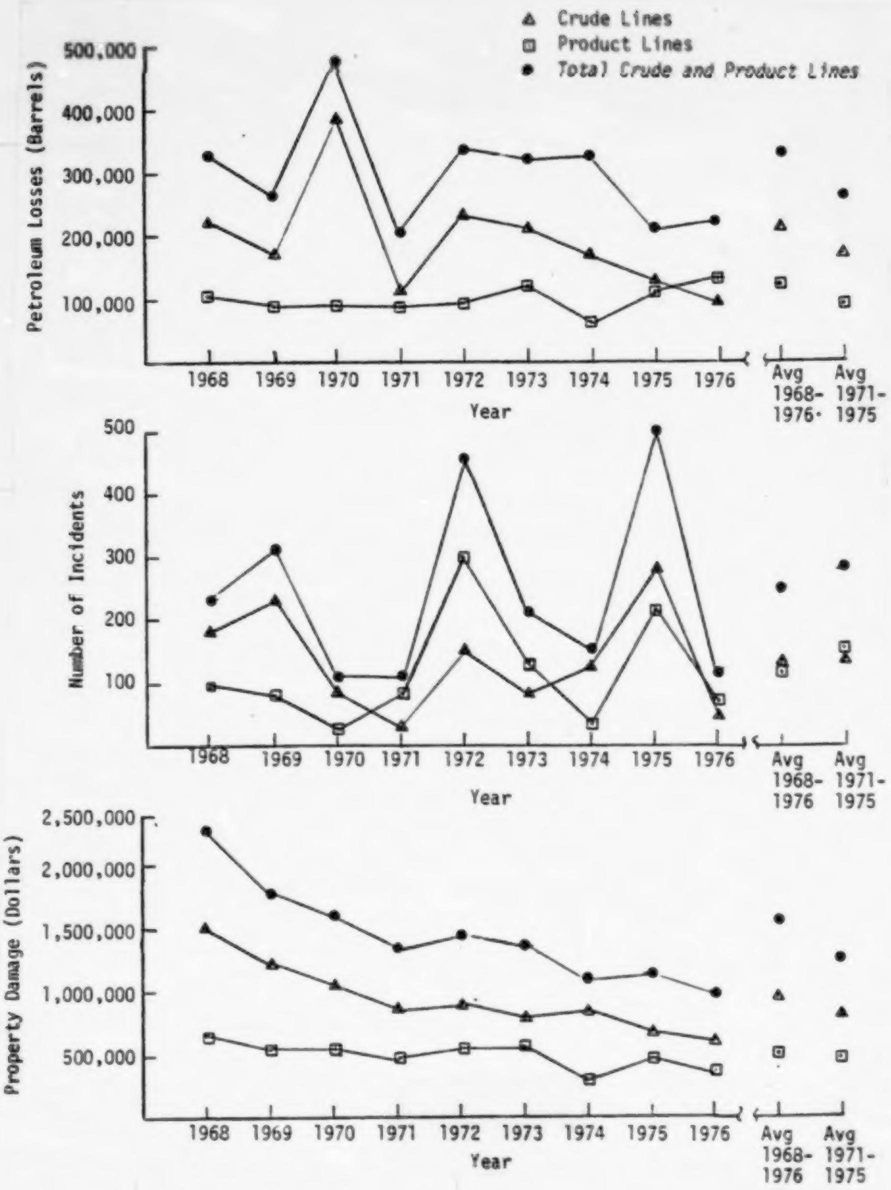


Figure 42. Damage from petroleum pipeline system incidents reported to OPSO between 1968-1978 for crude and product.

TABLE 36. NUMBER AND VOLUME OF SPILLS EACH YEAR, 1971-1975, GULF OF MEXICO OUTER CONTINENTAL SHELF[a]

Year	Spills of less than 50 barrels: Less than 1 bbl	1-14 bbl	15-49 bbl	Total	Spills of 50 barrels or more[b]: 50-499 bbl	500-999 bbl	1,000-9,999 bbl	10,000 bbl or more	Total	All spills Total
					Number of spills					
1971.....	913	321	11	1,245	11	0	0	0	11	1,256
1972.....	953	202	4	1,159	2	0	0	0	2	1,161
1973.....	1,005	162	4	1,171	1	0	3	0	4	1,175
1974.....	1,051	75	3	1,129	6	0	1	1	8	1,137
1975.....	1,021	100	5	1,126	2	0	0	0	2	1,128
					Total volume (barrels) of spills					
1971.....	228	1,008	257	1,493	1,285	0	0	0	1,285	2,778
1972.....	238	703	91	1,032	150	0	0	0	150	1,182
1973.....	251	585	85	921	240	0	21,935	0	22,175	23,096
1974.....	263	329	75	667	675	0	2,213	19,833	22,721	23,388
1975.....	255	344	112	711	266	0	0	0	266	977

[a] Source: Reference 25.

[b] Includes seven spills of 50 barrels each: 5 spills in 1971, and 1 spill each in 1972 and 1974.

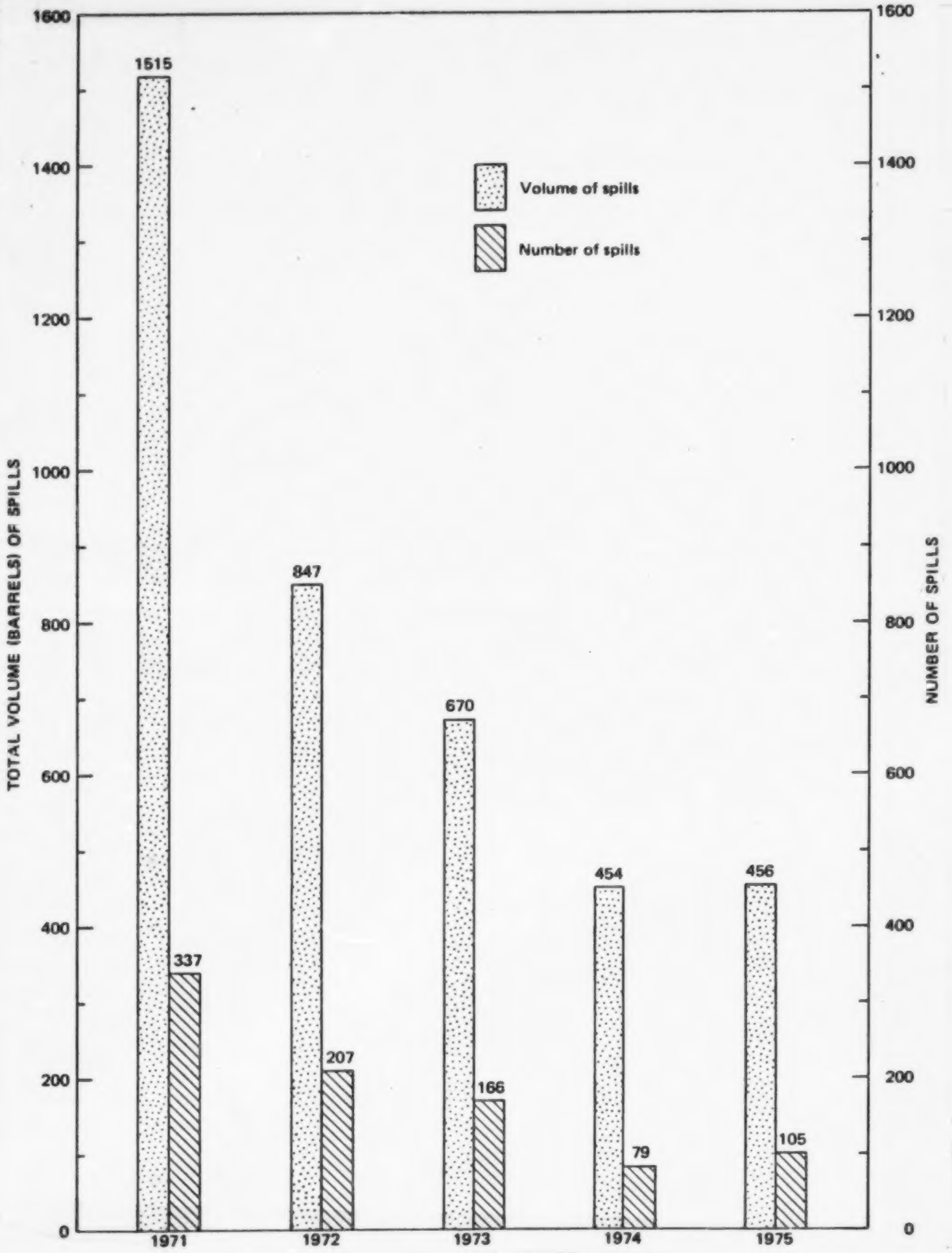


Figure 43. Number and volume of 10 to 50-barrel spills by year, 1971-75, Gulf of Mexico outer continental shelf. (Source: Reference 25.)

4.6.2.3 Loss Mechanism--Underwater OCS Pipeline Spills in the U.S. (OCS Statistics)--

A total of 17 spills exceeding 50 barrels were reported for underwater pipelines in the Gulf of Mexico Outer Continental Shelf between 1966 and 1976. It is estimated that there is 2500 miles of pipeline. Thus, the spill frequency are estimated to be:

$$\frac{17\ \text{spills}}{10\ \text{years}} \times \frac{1}{2500\ \text{miles}} = 6.8 \times 10^{-4}\ \frac{\text{spills}}{\text{mile-year}}\ (> 50\ \text{barrels}) \quad .$$

A total of 236 spills occurred from these underwater pipelines between 1966 and 1976; 85 percent of the total reported spills in the Gulf of Mexico were less than 50 barrels.

The spill frequency for all spills is estimated to be:

$$\frac{236\ \text{spills}}{10\ \text{years}} \times \frac{1}{2500\ \text{miles}} = 9.4 \times 10^{-3}\ \frac{\text{spills}}{\text{mile-year}}\ (\text{all spills}) \quad .$$

4.6.2.4 Loss Mechanism--Oil Spills in and About U.S. Waters (USCG Statistics)--

PIRS Statistics of oil spills in and about U.S. waters compiled by the USCG include spills from all sources. These spill statistics cover a broad area but are not as comprehensive as the OPSO data for pipeline system spills.

Spills--Volume, Number, Location, Cause

From 1970 to 1975, total losses, number of spills and average volume in and about U.S. waters[29] are shown in Figure 44. The general areas and location in which these losses occurred in 1975 are given in Table 37. Sources and causes of losses are given in Tables 38 and 39.

4.6.2.5 Gathering/Distribution, Drilling and Production Spills Between 1970 and 1971--

Early spill data (see Tables 40-42), recorded primarily during the 2-year period between 1970 and 1971, were tabulated and reviewed in Reference 30 for U.S. and foreign data sources (see Table 43). Over 15,000 oil spill events from gathering/distribution/drilling and production systems were reviewed. Of these, 8,473 oil spills were applicable to the study.

Detailed information is provided on spills, such as component failures, causes of failures and spill distribution. However, factors relating to pipeline system spills, such as component age and geometry, and information on total spill volume and throughput are not included in the study.

Tables 40-42 provide a summary of component versus quantity spilled category by system for gathering/distribution, drilling and production

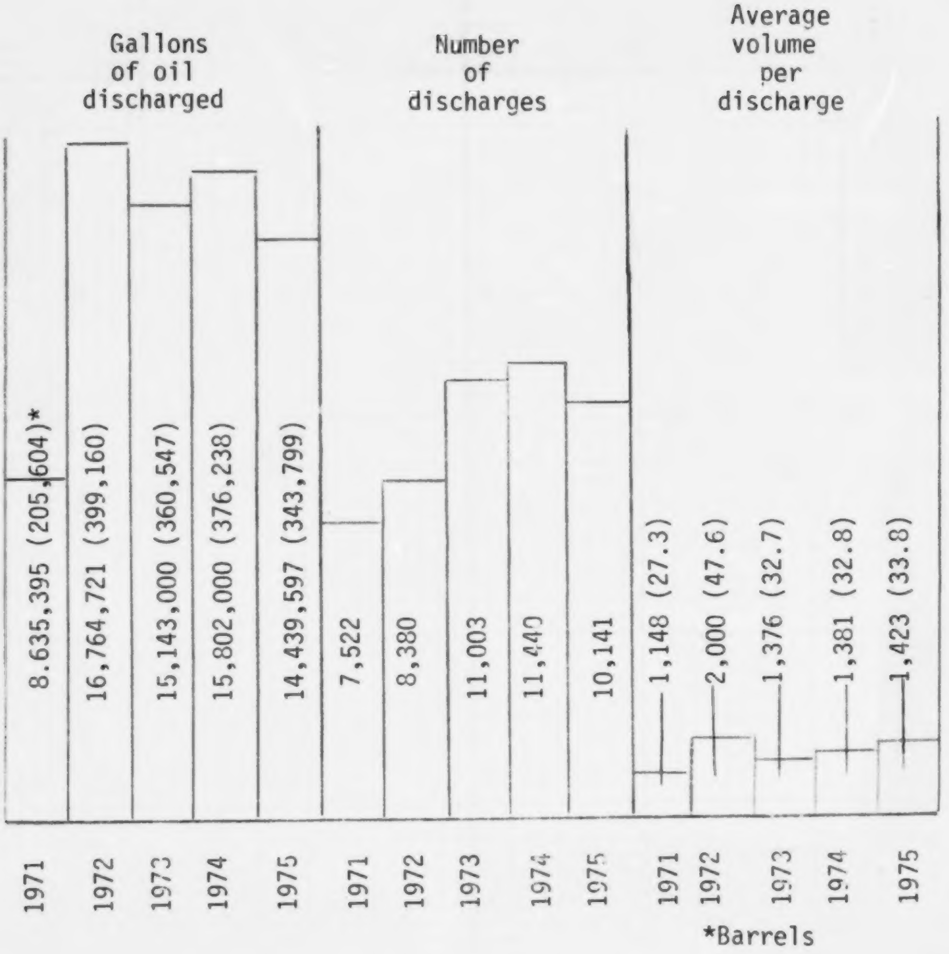


Figure 44. Discharge trends for oil only for calendar years 1970-1975. (Source: Reference 29.)

TABLE 37. GENERAL AREAS AND LOCATIONS OF SPILLAGE IN AND ABOUT U. S. WATERS[a], REPORTED TO USCG IN 1975[a]

Item	Number of incidents	% of Total	Volume in gallons	% of Total
General Area:				
Atlantic Coast	2,695	26.6	1,465,689	10.2
Gulf Coast (West of Long. 83°15')	3,315	32.8	5,430,212	37.6
Pacific Coast	1,768	17.4	440,923	3.0
Great Lakes	454	4.4	307,772	2.1
Inland U.S.	1,909	18.8	6,795,001	47.1
Total	10,141	100.0	14,439,597	100.0
Type of Location:				
Inland Waters				
Roadsteads	120	1.0	37,164	0.3
Ports	472	4.8	1,106,611	7.7
Beaches	96	0.9	88,537	0.6
River areas	836	8.2	3,816,371	26.4
Non-navigable areas	112	1.1	303,752	2.1
Total	1,636	16.0	5,352,435	37.1
Coastal Waters (including Great Lakes)				
Bays, estuaries and sounds	1,117	11.0	3,227,563	22.3
Ports	3,937	38.9	2,173,847	15.1
Beaches	159	1.6	108,588	0.8
River areas	1,272	12.5	2,008,819	13.9
Non-navigable areas	192	1.9	214,447	1.5
Open waters (Great Lakes or territorial sea)	955	9.4	453,683	3.1
Total	7,632	75.3	8,186,947	56.7
Contiguous Zone	188	1.9	5,725	0.0
High Seas	692	6.8	894,490	6.2
Total	10,141	100.0	14,439,597	100.0

---

[a] Source: Reference 29.

TABLE 38. CAUSES OF SPILLS IN ABOUT U.S. WATERS, REPORTED TO USCG IN 1975[a]

Item	Number of incidents	% of Total	Volume in gallons	% of Total
Hull/tank rupture/leak	757	7.5	6,359,433	44.0
Transportation pipeline rupture leak	235	2.3	1,200,004	8.3
Other structural failure	200	2.0	2,744,656	19.0
Pipe rupture/leak	954	9.5	1,322,385	9.2
Hose rupture/leak	220	2.1	120,203	0.8
Valve failure	256	2.5	251,608	1.7
Pump failure	110	1.0	39,499	0.3
Other rupture/leak	29	.2	94,683	0.7
Other equipment failure	1,069	10.5	221,956	1.5
Tank overflow	464	4.5	473,454	3.3
Improper handling operation	679	6.5	276,226	4.3
Other personnel error	511	5.1	504,976	3.5
Bilge pumping	195	1.9	14,821	0.1
Ballast pumping	21	.2	754	0.0
Other intentional discharge	269	2.6	196,089	1.4
Natural or chronic phenomenon	352	3.5	144,115	1.0
Unknown/Miscellaneous	3,820	38.1	474,735	0.9
TOTAL	10,141	100.00	14,439,597	100.00

[a] Source: Reference 29.

TABLE 39. SOURCES OF SPILLS IN AND ABOUT U.S. WATERS, REPORTED TO USCG IN 1975[a]

Item	Number of incidents	% of Total	Volume in gallons	% of Total
Vessels:				
1. **Dry cargo ships**	277	2.7	21,843	0.2
2. **Dry cargo barges**	31	0.3	5,215	0.0
3. **Tank ships**	643	6.3	1,766,729	12.2
4. **Tank barges**	757	7.5	3,467,203	24.0
5. **Combatant vessels**	202	2.0	16,913	0.1
6. **Other vessels**	1,143	11.3	1,353,947	9.4
Total	3,053	30.1	6,631,850	45.9
Land Vehicles:				
1. **Rail vehicles**	27	0.4	576,507	4.0
2. **Highway vehicles**	263	2.6	356,601	2.4
3. **Other/unknown vehicles**	20	0.1	2,617	0.0
Total	310	3.1	935,725	6.4
Non-Transportation-Related Facilities:				
1. **Onshore refinery**	176	1.7	145,722	1.0
2. **Onshore bulk/storage**	305	3.0	476,768	3.3
3. **Onshore production**	233	2.3	2,626,992	18.2
4. **Offshore production facilities**	1,243	12.3	78,217	0.5
5. **Other facilities**	762	7.5	567,924	4.0
Total	2,719	26.8	3,895,623	27.0
Pipelines:	564	5.6	2,490,237	17.3
Marine Facilities:				
1. **Onshore/offshore bulk cargo transfer**	250	2.5	81,203	0.6
2. **Onshore/offshore fueling**	74	0.7	9,388	0.0
3. **Onshore/offshore nonbulk cargo transfer**	19	0.2	1,326	0.0
4. **Other transportation-related marine facilities**	80	0.8	7,239	0.0
Total	423	4.2	99,156	0.6
Land Facilities	167	1.6	200,962	1.5
Misc. Unknown	2,905	28.6	186,044	1.3
Total	10,141	100.00	14,439,597	100.00

[a] Source: Reference 29.

TABLE 40. COMPONENT VERSUS QUANTITY SPILL CATEGORY FOR GATHERING/ DISTRIBUTION SYSTEM, 1970-1971[a]

Spill Quantity / Component	Code	0.0 to 1.0 BBLS	1.1 to 2.5 BBLS	Total Minor Spills	2.6 to 10 BBLS	11 to 100 BBLS	101 to 250 BBLS	Total Moderate Spills	251 to 500 BBLS	501 to 1000 BBLS	1001 to 5000 BBLS	5001 to 10,000 BBLS	10,001 or More BBLS	Total Major Spills	Not Reported	Not Determined	Total Spills Gathering/ Distribution
		01	02		13	14	15		25	26	27	28	29		41	42	
Not Identified	00	3	3	8	62	205	35	302	35	19	11	1	4	70	29	1	410
Bell, Alarm	01																
Blowcase, Saltwater	03																
Box, Stuffing	05																
Cable	06																
Choke Bean	07																
Choke Body	08																
Choke Target	09																
Coil	10																
Coupling	12	1	1	2	5	13	8	26	4	4				8			36
Detector, Heat	14																
Diaphragm	15																
Disc - Rupture	16					1		1									1
Ells	17																
Fasteners	18					1	2	3									3
Fittings	19				3	10	5	18	9	3	2			14			32
Flange	20				3	5	3	11	4	1				5			16
Float	21					1		1									1
Float (oil-water)	23																
Foundation	24								2					2			2
Gasket	25	1	1	2	8	23	6	37	2	1				3			42
Gasket, Ring	26	1		1													1
Gauge	27				1			1									1
Gland, Packing	28				1	7	3	11	1	1	1			3			14
Glass, Sight	29																
Header	30				1	3		4									4
Heater	31																
Hose	34					2		2	2					2			4
Joint, Blast	38					1		1									1
Liner	39																
Meter	40								2	2		1		5			5
Nipple	41	1		1	4	10	5	19	1	1			1	3	1		24
O-Ring	43				1	1		2									2
Packers	44				1			1									1
Pig	45	1		1	2			2									3
Pipe	46	21	26	47	493	1856	438	2787	332	136	124	13	3	608	63	1	3506
Piston	47																
Plug, Ball	48					6		6	2	3				5			11
Pump	49	1	3	4	6	7		13							5		22
Regulator, Pressure	52						1	1									1
Relay, Electric	53																
Mixer	55		1	1		4		4	1					1			6
Rod	56					1	1	2									2
Rod Polished	57																
Screen	58																
Seal	59				1	3	2	6		1				1			7
Seam	60				1			1	1		1			2			3
Sensor, Hi Level	61																
Sensor, Lo Level	62																
Sensor, Hi Pressure	63																
Sensor, Lo Pressure	64																
Swage	65					2		2									2
Switch	66									1				1			1
Tank Shell	67				1	1	1	3		1	1			2	1		6
Tee	68				1	5		6									6
Threads	69				2	1	1	4	2		1			3	1		8
Tubing Hanger	70																
Tubing Instrument	71					3		3	1					1			4
Union	72				1	1		2									2
Union - Flange	73					1		1									1
Valve	74	1	2	3	12	31	11	54	12		8			20			77
Valve - Back Pressure	75																
Valve - Ball	76																
Valve - Body	78																
Valve - By Pass	79				1	3		4									4
Valve - Check	80				11	31	4	66	1	1				2			68
Valve - Control	81					1		1									1
Valve - Dump	82																
Valve - Gate	83				4	17	7	23	2	1	1			4			32
Valve - Needle	84																
Valve - Plug	85																
Valve - Pressure Relief	86					1	1	2	1		1			2			4
Valve - Trim	87																
Vessel - Pressure	88					1		1									1
Welds	89				1	4	3	8	5	3	7	2		17	1		26
Motor	91					1		1		1	1			2			3
Fire Tube	92																
Control	93					2		2		1	1	1		3			5
Vent	94																
Tank-Test	95																
Oil/Log	96																
Water/Log	97																
Fuel Line/Supply	98																
Strainer	99				1	4	1	6	3		2			5			11
Totals	—	33	37	70	628	2290	338	3436	423	181	182	18	8	794	101	2	4423

[a] Source: Reference 30.

TABLE 41. COMPONENT VERSUS QUANTITY SPILL CATEGORY FOR DRILLING SYSTEM, 1970-1971[a]

Spill Quantity / Component	0.0 to 1.0 BBLS 01	1.1 to 2.5 BBLS 02	Total Minor Spills	2.6 to 10. BBLS 13	11 to 100 BBLS 14	101 to 238 BBLS 15	Total Moderate Spills	239 to 500 BBLS 25	501 to 1000 BBLS 26	1001 to 5000 BBLS 27	5001 to 10,000 BBLS 28	10,001 or More BBLS 29	Total Major Spills	Not Reported 41	Not Determined 42	Total Spills Drilling System
Not Identified	3		3	4	4	2	10		1		2		3	12	1	29
Bell, Alarm																
Blowcase, Saltwater																
Box, Stuffing																
Cable																
Choke Bean																
Choke Body											1		1			1
Choke Target																
Coil																
Coupling																
Detector, Heat																
Diaphragm																
Disc - Rupture		1	1													1
Ells																
Fasteners																
Fittings																
Flange																
Float																
Float (oil-water)																
Foundation																
Gasket																
Gasket, Ring																
Gauge																
Gland, Packing																
Glass, Sight																
Header																
Heater																
Hose																
Joint, Blast																
Liner																
Meter																
Nipple																
O-Ring																
Packers																
Pig																
Pipe		2	2											2	1	5
Piston																
Plug, Ball																
Pump																
Regulator, Pressure																
Relay, Electric																
Riser																
Rod																
Rod Polished																
Screen																
Seal																
Seam																
Sensor, Hi Level																
Sensor, Lo Level																
Sensor, Hi Pressure																
Sensor, Lo Pressure																
Swage																
Switch																
Tank Shell																
Tee																
Threads																
Tubing Hanger																
Tubing Instrument																
Union																
Union - Flange																
Valve																
Valve - Back Pressure																
Valve - Ball																
Valve - Body																
Valve - By Pass																
Valve - Check																
Valve - Control																
Valve - Dump																
Valve - Gate																
Valve - Needle																
Valve - Plug																
Valve - Pressure Relief																
Valve - Trim																
Vessel- Pressure																
Welds																
Motor																
Fire Tube																
Control		1	1													1
Vent																
Tank-Test																
Oil/Leg																
Water/Leg																
Fuel Line/Supply																
Strainer																
Totals	3	4	7	4	4	2	10		1		3		4	14	2	37

[a] Source: Reference 30.

TABLE 42. COMPONENT VERSUS QUANTITY SPILL CATEGORY FOR PRODUCTION SYSTEM AND ALL SYSTEMS, 1970-1971[a]

Spill Quantity / Component	Code	0.0 to 1.0 BBLS 01	1.1 to 5.0 BBLS 02	Total Minor Spills	5.1 to 10. BBLS 13	11 to 100 BBLS 14	101 to 250 BBLS 15	Total Moderate Spills	250 to 500 BBLS 25	501 to 1000 BBLS 26	1001 to 5000 BBLS 27	5001 to 10,000 BBLS 28	10,001 or More BBLS 29	Total Major Spills	Not Reported 41	Not Determined 42	Total Spills Production System	Total Spills All Systems
Not Identified	00	109	69	178	201	347	109	657	60	7	8	1	2	78	308	2	1222	1662
Bell, Alarm	01	4		4	1	3		4									8	8
Blowcase, Saltwater	03	3	4	7	2			2	1					1			10	10
Box, Stuffing	05	2	2	4	22	28	1	51							33		88	88
Cable	06				1	1		2									2	2
Choke Bean	07	1	1	2													2	2
Choke Body	08	4	2	6	10	1		11							1		18	19
Choke Target	09	2		2	1	1		2									4	4
Coil	10					1		1									1	1
Coupling	12	4		4	5	22	3	30							2		36	72
Detector, Heat	14	1		1													1	1
Diaphragm	15		1	1	1	2		3									4	4
Disc - Rupture	16	7	9	16	21	20	1	42	2					2	2		62	64
Ells	17	2	1	3	7	4		11									14	14
Fasteners	18	1		1	1	2	2	5									6	9
Fittings	19	1	1	2	5	13	1	19							4		25	57
Flange	20	8	2	10	4	4	1	9									19	35
Float	21	1	2	3	2	1		3									6	7
Float (oil-water)	23														1		1	1
Foundation	24				1	7	3	11	4					4			15	17
Gasket	25		1	1	7	6	1	14	1					1	1		17	18
Gasket, Ring	26																	1
Gauge	27	1		1	4	2		6		1				1	1		9	10
Gland, Packing	28	2	1	3	5	6		11							2		16	30
Glass, Sight	29				3	6		9									9	9
Header	30	2		2	4	4		8									10	14
Heater	31	2		2	1	1	2	4							6		12	12
Hose	34	7	5	12	4	10	1	15	2					2			29	33
Joint, Blast	36																	1
Liner	39	1		1	2	1		3									4	4
Meter	40	1		1	1	5	1	7		1	1			2			10	15
Nipple	41	3		3	11	18	3	32							1		36	60
O-Ring	43		3	3	2	1		3									6	8
Packers	44	1	1	2	1	1		2							1		5	6
Pig	45					1		1	1					1			2	3
Pipe	46	58	37	95	294	546	78	920	31	12	3		1	47	72	1	1135	4646
Piston	47		1	1			1	1									2	2
Plug, Bull	48	3	1	4	5	5		10	1					1			15	28
Pump	49	8	14	22	24	28	6	58		1	1			2	14		96	118
Regulator, Pressure	52		2	2	5			5									7	8
Relay, Electric	53					1		1									1	1
Riser	55	6	1	7	2	1		3									10	16
Rod	56	1		1	1	1	1	3							1		5	7
Rod Polished	57		1	1	4	2	1	7									8	8
Screen	58		1	1													1	1
Seal	59				3			3									3	10
Seam	60	1		1													1	4
Sensor, Hi Level	61	13	17	30	42	16		58		1				1	3		92	92
Sensor, Lo Level	62	2	3	5	1	1		2									7	7
Sensor, Hi Pressure	63				2	4		6							4		10	10
Sensor, Lo Pressure	64				1			1							1		2	2
Surge	65				1	2	1	4									4	6
Switch	66	1	1	2	4	17		21	3					3			26	27
Tank Shell	67				3	19	9	31	5	2				7	11		49	55
Tee	68	2		2	5	1		6									8	14
Threads	69					3		3									3	11
Tubing Hanger	70				1			1									1	1
Tubing Instrument	71																	4
Union	72	4	2	6	1	6		7							1		14	16
Union - Flange	73																	1
Valve	74	14	10	24	57	129	32	218	27	5	3			35	23		300	377
Valve - Back Pressure	75		1	1	3	12	1	16							1		18	18
Valve - Ball	76				1			1							1		2	2
Valve - Body	78	1		1	2	2	1	5									6	6
Valve - By Pass	79		1	1	1	1		2							1		4	8
Valve - Check	80	4		4	17	9	2	28	2					2	2		36	104
Valve - Control	81				1	5	2	8	1					1	1		10	11
Valve - Dump	82	25	29	54	70	65	15	150	11		1			12	6		222	222
Valve - Gate	83					2	3	5									5	37
Valve - Needle	84	1		1		3		3									4	4
Valve - Plug	85					1		1									1	1
Valve - Pressure Relief	86	10	14	24	17	7		24							2		50	54
Valve - Trim	87		3	3	1			1									4	4
Vessel- Pressure	88				2	2		4							1		5	6
Welds	89								1					1			1	27
Motor	91		3	3	3	4	2	9		1				1			13	16
Fire Tube	92				3	11	1	15		1				1			16	16
Control	93	6	4	10	11	7	1	19	4		1			5			34	40
Vent	94				2	2		4	1					1	5		10	10
Tank-Test	95	3	1	4	3	1		4							1		9	9
Oil/Leg	96				2	3	3	8	1					1	2		11	11
Water/Leg	97				4	11	2	17	1	1				2		1	20	20
Fuel Line/Supply	98				1			1									1	1
Strainer	99				1			1									1	12
Totals	—	333	252	585	933	1449	291	2673	160	33	18	1	3	215	516	4	3993	8453

[a]Source: Reference 30.

TABLE 43. SOURCE DATA SUMMARY[a]

Item	Number of Records Used	Type of Report		Table Number	Systems Reported[b]
		Form	Narrative		
Federal:					
EPA Headquarters - OHM File	108		X	D-1	G/D, D, P
EPA Anchorage, Alaska	68		X	D-2	D,P
DOT/FRRC - Pipeline Carrier Accident Reports	802	X		D-3	G/D
U.S. Geological Survey, Conservation Division, Washington, D.C. Office	633	X		D-4	G/D, D, P
States:					
California - Department of Fish and Game Commission	63		X	D-5	G/D, P
California - Water Quality Control Board	19	X		D-6	G/D, D, P
California - Division of Oil and Gas	40		X	D-7	G/D, D, P
California - City of Long Beach, Department of Oil Properties	30		X	D-8	G/D, D, P
Colorado - Department of Health, Water Pollution Control Division	10	X		D-9	G/D, P
Louisiana - Department of Conservation, Division of Minerals	707	X		D-10	G/D, P
Mississippi - Oil and Gas Board	202		X	D-11	G/D, P
New Mexico - Oil Conservation Commission	58		X	D-12	G/D, P
Oklahoma - Corporation Commission Oil and Gas Conservation Division	399	X		D-13	G/D, D, P
Texas - Railroad Commission Oil and Gas Division	5094	X		D-14	G/D, D, P
Other:					
Alberta, Canada - Alberta Oil and Gas Conservation Board	235		X	D-15	G/D, D, P

[a] Source: Reference 30.

[b] G/D - Gathering/Distribution Systems
D - Drilling Systems
P - Production Systems

systems during the 1970 through 1971 period. Figure 45 illustrates data from Tables 40-42 for pipeline spills and total spills. These data show that of the 8,453 total spills, over 7,900 spills greater than 2.5 barrels occurred for all oil system components. Of the total 4,646 pipe spills, 4,500 spills were greater than 2.5 barrels, 3,815 spills greater than 10 barrels and 1,413 spills greater than 100 barrels. Pipe spills represented over 81 percent of the 4,423 spills from the gathering/distribution system and over 39 percent of the 3,993 from production systems. Spills from drilling systems were negligible, representing less than 1 percent of the total number of spills.

4.6.2.6 Loss Mechanism--Cross-Country Oil Spillage in Europe and Canada--

Cross-country spillage data in Europe are compiled annually by Stichting Concawe Oil Pipeline Special Task Force[31-37]. Reported spill information includes date, cause, amount of spillage, damage, cost of cleanup, pipeline dimensions and total pipeline length. Spill volumes below about 1 barrel were not reported. Similar spillage data for Canada pipelines is also compiled periodically.

Spill Volume for Mileage and Throughput

A summary of the reported spill data is tabulated in Table 44. Reported spill volume between 1966 and 1976 averaged about 9,500 barrels of petroleum a year. The spill volume rate was estimated by dividing the average volume of spills (1966-1976) by the average pipeline mileage (1971-1975):

$$\frac{\text{9,538 barrels/year}}{\text{8,941 miles}} = 1.06 \; \frac{\text{barrels spilled}}{\text{mile-year}} \quad .$$

Reported spill volume between 1971 and 1975 averaged 8,865 barrels. The spill volume rate was estimated by dividing the average volume of spills by the average pipeline mileage for those years:

$$\frac{\text{8,865 barrels/year}}{\text{8,772 miles}} = 1.01 \; \frac{\text{barrels spilled}}{\text{mile-year}} \quad .$$

These average volumes spilled are similar to that reported for the U.S. pipeline.

The average percentage of the volume of oil spilled for the barrels of throughput in Western Europe between 1966 and 1976:

$$\frac{\text{104,966 barrels (spilled)}}{\text{25,240,000,000 barrels (throughput)}} \times \frac{1}{11} = 0.004\% \text{ (all spills)} \quad .$$

This percent loss of throughput is an order of magnitude better than for the U.S. pipelines.

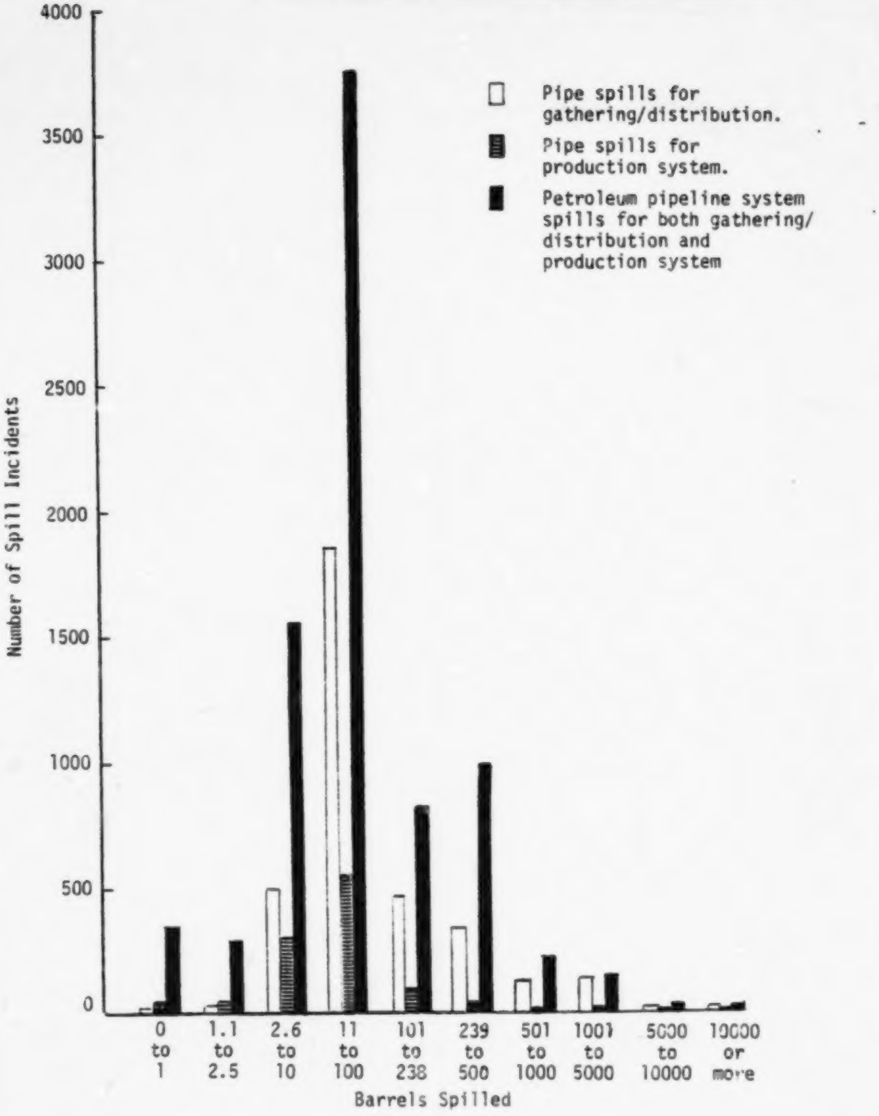


Figure 45. Pipe and petroleum pipeline system oil spills in the U.S. for gathering/distribution and production systems in the United States between 1970-1971. (Source: Reference 30.)

TYPING GUIDE SHEET

BEGIN FIRST LINE OF TEXT HERE
CENTER OF PAGE
TOP OF IMAGE AREA
DROPPED HEAD BEGIN SECTIONS HERE

TABLE 44. CROSS-COUNTRY SPILL DATA FOR WESTERN EUROPE

			Loss			Incidents	
Year	Throughput (Barrels)	Length[a] (Miles)	Barrels	% Throughput	$\frac{\text{Barrels}}{\text{Mile}}$	Spills	10^{-3} $\frac{\text{Spills}}{\text{Mile}}$
1966	1,333,000,000	NA	9,603	0.00072	NA	5	NA
1967	1,408,000,000	NA	2,075	0.00015	NA	5	NA
1968	1,484,000,000	NA	62	0.000004	NA	2	NA
1969	1,559,000,000	NA	3,867	0.00025	NA	6	NA
1970	1,572,000,000	NA	4,522	0.00028	NA	11	NA
1971	1,940,000,000	6,920	17,176	0.0009	2.48	11	1.59
1972	2,723,000,000	8,540	5,660	0.0006	0.66	21	2.4
1973	3,509,000,000	9,351	6,735	0.0002	0.72	20	2.1
1974	3,290,000,000	9,378	12,260	0.0004	1.3	18	1.9
1975	3,037,000,000	9,675	2,496	0.00008	0.26	20	2.1
1976	3,390,000,000	9,783	3,165	0.00009	0.32	14	1.4
1966-1976							
Total	25,245,000,000	53,647	104,926			133	
Average	2,295,000,000	8,941	9,538	0.0004	1.06	12	1.3
1971-1975							
Total	14,499,000,000	43,864	44,327			90	
Average	2,899,000,000	8,772	8,865	0.0003	1.01	18	2.0

[a] Not reported in References 31-37.

BEGIN LAST LINE OF TEXT

TYPING GUIDE SHEET

Spill Frequency for Pipiline Mileage

The number of spillages reported between 1966 and 1976 averaged about 12 and showed a significant increase over this period. The spill rate was estimated by dividing the average number of spills by the average pipeline mileage (1971-1976):

$$\frac{12\text{ spills/year}}{8{,}941\text{ miles}} = 1.3 \times 10^{-3}\ \frac{\text{spills}}{\text{mile-year}} \quad .$$

Reported number of spills between 1971 and 1975 averaged 18. The spill rate for the period was obtained by dividing the average number of spills by the average pipeline mileage:

$$\frac{18\text{/year}}{8{,}772\text{ miles}} = 2.05 \times 10^{-3}\ \frac{\text{spills}}{\text{mile-year}} \quad .$$

This spill rate is similar to that reported in the U.S. if statistical estimated of spills of less than 50 barrels are included in the U.S. total.

Spill Frequency for Pipeline Size

A relationship of mean spill size to pipe diameters based on European (1971-1974) and Canadian (1965-1972) data is presented in Reference 37. Figure 46, see Reference 39, shows a plot of the mean spill size and pipe diameter. Also included in the plot are U.S. data (1971-1975) from OPSO statistics. Results show that mean spill size was a function of pipe diameter to the exponent 2.27 and essentially proportional to the cross-sectional area of the pipe. Insufficient data were available to establish a relationship of pipe diameter with either spill frequency or volume transported.

Spill Size Distribution

Spill size distribution based on European and Canadian data (see Reference 39) is presented in Figure 47. The standard deviation for 1971-1974 European data is used for both distributions. The mean spill size in the Canadian data was 3,407 barrels, and 666 barrels for the European data.

Spill Probability for Various Pipeline Diameters

The recurrence and probability of spills from various pipeline diameters can be obtained using the distribution and the following equations:

$$R(S) = \frac{100}{\overline{N}\left[100-F(S)\right]} \tag{1}$$

$$P(S) = 1-e^{-\frac{T\overline{N}}{100}\left[100-F(S)\right]} = 1-e^{\frac{-T}{R(S)}} \tag{2}$$

$$\overline{V} = \overline{N}\ \overline{S} \tag{3}$$

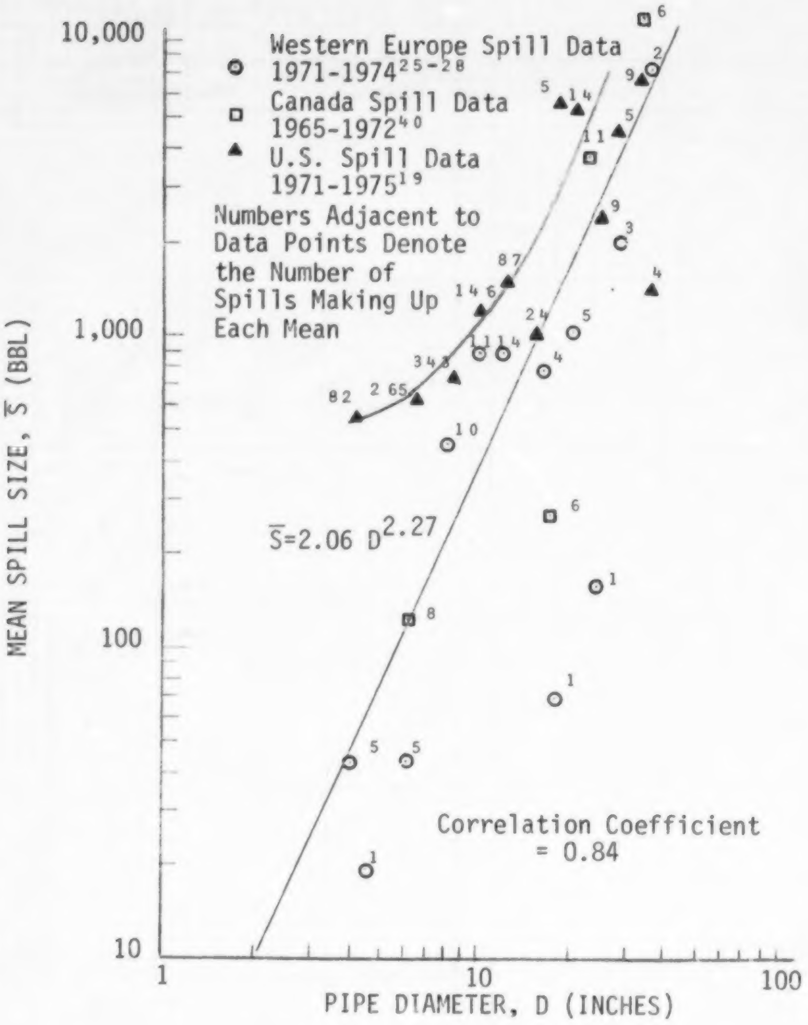


Figure 46. Cross-country pipeline mean spill size versus pipe diameter

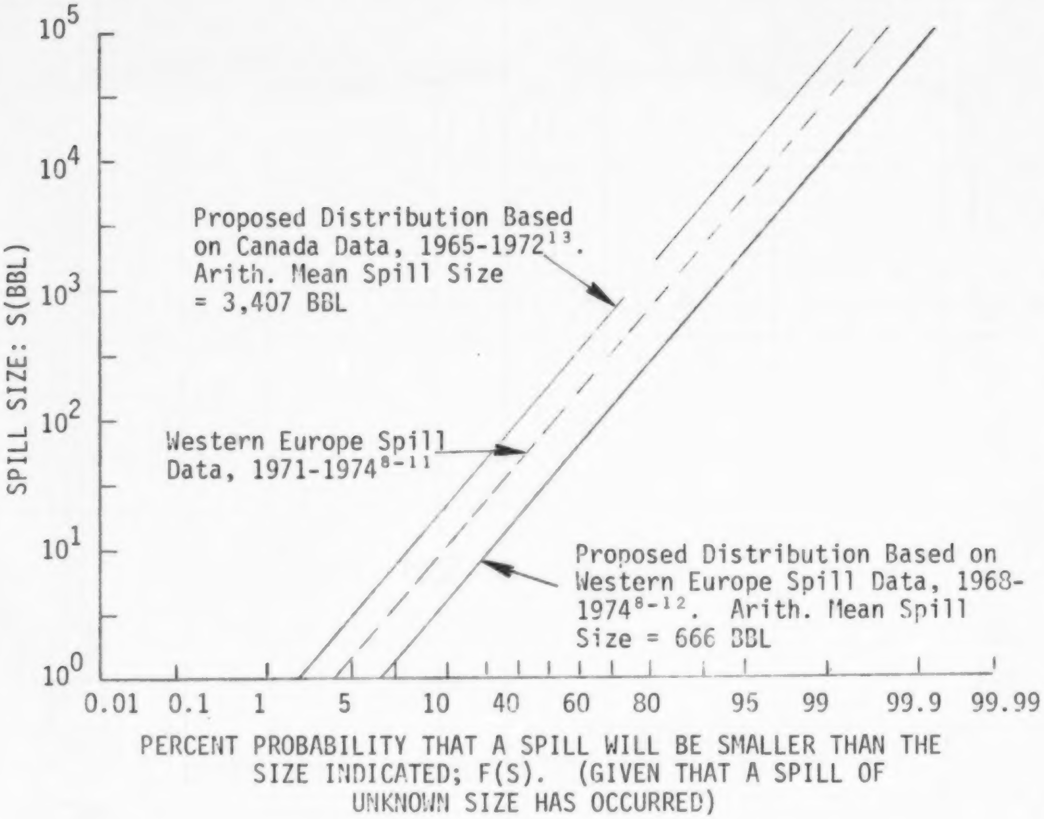


Figure 47. Cumulative size distribution for oil industry cross-country pipeline spills, Western Europe and Canada (assorted pipe diameters). (Source: Reference 39.)

where

R(S) = recurrence interval (years) for spills of size ($\geq$ S (i.e., the average time interval between spills of size greater than or equal to S)

N = mean number of spills per year

F(S) = cumulative spill size distribution function (i.e., the percent probability that a spill will be smaller than size S, given that a spill of unknown size has occurred). F(0) = 0

P(S) = fractional probability of having at least one spill of size > S during time T (assumes Poisson distribution for spill frequency)

T = time interval of interest (years)

$\overline{V}$ = average annual spillage (bbl)

$\overline{S}$ = mean spill size (bbl).

4.7 TOTAL PETROLEUM LOSSES--PIPELINE SYSTEMS

Total petroleum losses from pipeline systems in the United States are estimated to be approximately 0.16 percent to 0.22 percent of throughput. The exact petroleum throughput in the U.S. is uncertain because of routing. From BOM statistics of volume of petroleum transported in 1975 by pipelines (see Table 5), approximately 8.0 billion barrels are transported. Crude transported was about 4.7 billion barrels, or slightly greater than one-half of the total petroleum transported. Assuming losses of about 0.22 percent of throughput (0.16 percent crude, 0.33 percent product), this results in an estimated loss of 17.2 million barrels by pipeline systems. Cumulative estimates of annual losses for individual mechanisms are as follows: about 0.05 percent from evaporation; 0.05 percent from admixture shrinkage; and 0.02 percent from coefficient of expansion errors. Losses from spills are uncertain because of the various reporting problems indicated in Section 4.6.2. However, it appears that total annual spillage losses can range from as low as 0.01 percent of throughput or about 800 thousand barrels to as high as 0.03 percent of throughput or about 2.4 million barrels.

SECTION 5

PIPELINE SYSTEM LEAK DETECTION AND INSPECTION METHODS

Leak detection and inspection methods for petroleum pipeline systems which might reduce the risk of oil spillage, i.e., reduce frequency of spills or limit the volume of oil lost, are presented in this section. Because of the high incidence of pipeline (line pipe) spills, i.e., high risk of oil spills, and the potential for significant reductions of the oil spill risks, major emphasis is given to detecting and preventing leaks from line pipe failures. However, methods are also included for other pipeline system components.

A general discussion of leak detection, inspection and maintenance is given in Section 5.1. Pipeline system component failures, leakage and discharge rates are discussed, and difficulties associated with leak prevention, detection and location are identified.

Section 5.2 provides a general description of leak detection and inspection methods. Type, mode, application, use and installation are defined and discussed. Methods for detecting liquid leaks and failures that might result in leakage are discussed. Preventing leakage by incipient (impending) failure detection and minimizing leakage volume through early detection of leakage is emphasized.

Specific leak detection and inspection methods are identified and compared in Section 5.3. Each method is included in one of ten categories.

Section 5.4 presents the current status of these methods. Existing domestic and foreign regulations and current recommended practices for inspection and leak detection of liquid and gas pipeline systems are reviewed.

5.1 GENERAL DISCUSSION

5.1.1 Definitions--Leak Detection, Inspection, Maintenance

In this study, leak detection methods are defined as methods that are capable of detecting any pipeline system leakage. Inspection methods are defined as methods that are capable of testing the integrity of the pipeline system. Inspection methods include ones that detect internal defects, defects that cause insignificant small leaks such as leaking seals, or line conditions that might result in failure and cause an oil spill. Thus, inspection methods, as defined here, may include some leak detection methods. Hydrostatic pressure testing, for example, is considered to be both a leak detection and an inspection method, whereas pressure deviation and flow deviation methods are considered as leak detection methods only.

Maintenance is defined as keeping equipment, components, or systems in a continuing state of proper working order. In some applications, maintenance may be considered as an inspection. For example, checking that the cathodic protection system is operating properly is considered either maintenance or inspection of the pipeline system. Periodic cleaning of the interior of the line pipe with pigs to inspect for foreign matter or remove excessive water at low elevation areas is considered as both inspection and maintenance. However, periodic cleaning of foreign matter from the interior of the line pipe, scraping the line pipe walls to maintain an internally smooth line pipe, or installing of interior or exterior protective line coatings are considered as maintenance.

5.1.2 Pipeline System Component Failures

Major emphasis in this study is the prevention of pipeline failures rather than failures of other pipeline system components. Justification is based upon three main reasons. First, oil spill statistics (see Section 4.6.2) show that most spills (over 80 percent) and fluid losses of petroleum from pipeline systems are due to pipeline failures. Secondly, pipeline spills currently present a much greater risk (see Section 6.2) than other pipeline system components. For example, most onshore tank storage facilities with associated components are protected by a secondary containment system that virtually eliminates petroleum leakage outside the facility. Finally, the most cost-effective means of reducing spill incidents and volume, thereby minimizing environmental pollution, is expected through the implementation of a viable and optimized spill prevention program for pipelines. This would consist of scheduled inspections and/or leak detection to test the condition of the line and check for the presence of leaks.

5.1.3 Leakage, Discharge Rates, and Spill Volume--Ruptures, Breaks, Cracks, Pinholes

Petroleum leakage[a] is difficult to prevent, detect and locate. These difficulties exist for two main reasons. First, many variables contribute to pipeline system failures that result in leakage. Secondly, actual leadage can occur in many different ways (critical failure, cracks, etc.), at almost any location and at almost any discharge rate.

Pipeline leaks are usually caused by corrosion, hydrogen embrittlement, defective pipe seams and welds, equipment rupturing the line, external impacts, and natural causes. Results in Section 4.6.2.1 show that over half of the pipeline spills and spill volume were caused by pipeline faults.

---

[a] Note: The terms "leak" and "spill" are commonly used to describe the same event and will be used interchangeably in this study. However, a leak is normally considered as a gradual escape of a fluid, while a spill is normally considered an overflow or rapid escape of oil.

These could be reduced significantly by new methods and/or increased frequency of inspections. Pipeline accidents caused by outside forces, i.e., equipment rupturing the line, anchor dragging, etc., account for about one-third of the spill volume and less than one-third of the spill incidents. These accidents can be reduced somewhat by implementing prevention programs such as the One-Call System recommended in Reference 12. However, effective continuous monitoring of leak detection and inspection methods might also reduce the incidence of damage by outside forces.

There are several ways in which leakage might occur. These include:

- Small holes or hairline cracks
- Medium to large holes or cracks
- Large cracks that are continually growing in size
- Large cracks that have reached a critical size and rupture
- Large areas resulting from bursts or ruptures.

Small leaks are normally of pinhole size, are difficult to detect, and often exist for long periods of time before detection. These types of leaks account for a large number of spills, particularly for older pipelines. Although data on reported spills (see Section 4.6.2) show that small leaks account for a relatively low percentage of total spill volume, there is evidence to indicate that this might not be entirely correct. Also, even small leaks can be hazardous at certain locations. Large leaks and ruptures are defined here as medium or major spills. These account for most of the oil pollution incidents as well as a large percentage of the total spill volume. These leaks are normally detected by visual observation, but in many cases detection is too late to avoid serious pollution or large losses of oil. Spills at night, in water, or in remote areas have continued for days without detection.

Leakage from other pipeline system components also occurs in many different ways and varies widely. Leakage of very small amounts may occur through valve seals, gaskets, flanges, etc., or in large quantities through very large areas such as over the top of storage tanks during accidental overflow.

In most petroleum pipeline accidents, the spill discharge rate and volume varies considerably depending upon factors such as the location of the failed component (onland, underwater, depth of cover, etc.) type of failure (crack, rupture, etc.), flow condition and pipeline operations. The spill discharge rate of petroleum leakage normally occurs continuously, but in many instances discharge is transient or periodic. Very small leaks, for example, can occur intermittently because they have a tendency to become plugged by waxy particles or solids in the oil. Also, leakage can be into rather than out of a pipeline. In subsea pipelines where external pressures may be greater than internal line pressures, seawater could be forced into a cracked line.

Spill volume[a] can vary greatly. Typically, it ranges from the small volume of spills of pinhole leaks to the large volume spills of pipeline breaks or ruptures. Besides the cause, type of leak, and discharge rate, spill volume also depends upon the detection of the leak and the time required to shut the system down. Oil spill statistics of incidents reported to OPSO in Section 4.6.2.1.3 (Table 19) show that most small spills are caused by discharge of oil at a low discharge rate. Statistics for this type of spill indicate an average spill size of about 400 barrels. If estimated unreported spills were included, the average spill size would be somewhat lower. Outside forces are the most frequent cause of medium to large spills, and the average spill size is about 1,100 barrels. These also cause considerable spillage over a short time and create the potential of serious pollution incidents. Major spills are usually due to defective pipe, and the average spill size is about 2,100 barrels. In most cases, a considerable amount of spillage occurs over a short time.

5.1.4 Leak Detection and Inspection Methods

A wide variety of leak detection and inspection methods can be applied to detect petroleum leakage, internal defects that may result in leaks, or line conditions that may result in failures and cause an oil spill. Currently, no single method has been found by governmental research, private studies, or the oil industry that provides adequate protection against a serious oil spill incident. However, combined inspections and/or leak detection methods that verify the pipe condition and check for leakage have been shown to be effective in preventing and detecting leaks for particular pipeline systems. Methods such as visual observation of the line, hydrostatic tests that verify the tightness of the line, and on-stream leak detection and inspection methods have been implemented. Two of the most effective methods in preventing leaks are scheduled pressure testing of the line for detecting small pinhole leaks and inspecting the integrity of the line with inspection pigs. The current trend in leak detection and inspection by the U.S. petroleum pipeline industry has been in the development of low-cost continuous monitoring systems rather than inspections that require shutdown of the line. The objectives of these developmental systems are to provide rapid detection and location of a leak and shutdown of the line to minimize the volume of oil spilled.

Many modern large-diameter pipeline systems in the U.S. have some form of continuous monitoring leak detection system. However, variations in the pipeline system operating and flow conditions often cause false alarms from these systems. In order to account for this (reduce false shutdowns), set points are typically raised. This results in a decrease in the leak sensitivity and typically limits detection to only large spills. Also, these existing monitoring systems cannot detect a leak until the flow (pressure or flow rate changes) reaches a meter. Typically, meters might be located up to 50 miles apart and a large rupture-type spills, for example, might leak many thousands of barrels before a leak indication is even detected by a meter.

---

[a] Small spill < 2,100 gal (50 barrels); Minor spill > 10,000 gal (238 barrels); Medium spill, 10,000 to 100,000 gal; Major spill > 100,000 gal.

Variations in pipeline system size, age and other factors present problems in selecting the most effective leak detection and inspection methods. In general, serious pollution spill incidents and large losses of petroleum from modern pipeline systems are most likely to arise from medium to large spills caused by outside forces and defective pipeline seams and welds. Older lines have the additional problem of the high possibility of spill incidents from external pipeline defects caused by corrosion. Thus, leak detection and inspection that may be adequate for some lines are inadequate for others. Furthermore, even small spills may present serious hazards to segments of the population in some areas and cannot be tolerated. Thus, even more sensitive or reliable leak detection and inspection methods may be needed in these hazardous areas, e.g., see Section 7.4.2.

Because of the serious nature of pipeline spills, the many factors that contribute to pipeline system failures and leakage, and the different petroleum transportation systems in use, all potential leak detection and inspection methods will be reviewed in the subsections that follow. The most effective methods will be selected for evaluation in Sections 6 and 7.

5.2 GENERAL DESCRIPTION OF METHODS

In order to provide an overview of leak detection and inspection methods, a general description is given. For comparison purposes, these methods[a] are classified according to type, operational mode, application, installation and use in the following subsections.

5.2.1 Types of Methods

Two main types of leak detection and inspection methods exist. One type checks the line for actual fluid leaks. The other type detects either internal damage or line conditions that might results in a failure and cause an oil spill. The latter type is defined here as incipient or impending failure detection and is usually considered as an inspection method to prevent leaks.

5.2.1.1 Fluid Leak Detection--

Leak detection and inspection methods for petroleum pipeline systems detect either the actual oil leaking or events that are characteristic of oil leakage. Typically, these events include:

- Pressure drops
- Pressure fluctuations

---

[a] Some methods might be applicable to more than one use in a specific category. In these cases, the method is categorized as to the type of method for which it is best suited.

- Flow changes
- Temperature changes
- Sound level increases
- External pipe pressure
- Pipe variations
- Pipe acoustic energy releases
- Color changes
- Hydrocarbon vapors
- Vegetation changes.

Ideally, fluid leak detection and inspection methods should provide instantaneous detection and accurate location of leaks of any size to minimize the volume of petroleum lost and damage to the environment. In actual practice, the methods used are far from ideal. In fact, the only method commonly used in the U.S. is periodic visual observations of the line. In general, leaks are detected days after they occur, and even then precise location is difficult. Remedial action normally is too late to avoid large losses of oil and damage to the environment.

5.2.1.2 Incipient[a] (Impending) Failure Detection--

Incipient (impending) failure detection is the detection of pipeline flows, damage or external impacts that are just beginning to exist or appear and might result in a pipeline leak. This type of detection method normally is considered as an inspection to check the condition of the line. Some of the main ways these detection methods might be applied are:

- Detection of pipeline internal damage (cracks, corrosion, etc.) that potentially can result in a pipeline leak.

- Detection of external pipeline damage, such as impacts from outside forces, that can result in a pipeline leak.

- Detection of crack growths that can reach a critical size and result in rupture.

- Detection of pipeline flaws by applying a stress that is higher than what normally exists, i.e., proof testing at elevated pressures. Enhancement of defects can occur with high stresses and result in leakage or stress wave generation at a flawed area. Removal of the stress generally causes the defect to diminish almost to its original state and become undetectable by conventional flaw detection methods.

---

[a] Incipient failure detection and impending failure detection have the same meaning and are used interchangeably in this study.

One of the most common impending failure detection methods is to traverse the inside of the pipeline with an inspection pig to check for flaws *or corrosion damage in the pipeline. Data are normally tape recorded as* the inspection device is propelled through the line and then analyzed at a later time.

Incipient failure detection, which prevents accidents, is the most ideal way to minimize oil loss and oil pollution incidents. Although these methods are effective in reducing the frequency of spills, in actual practice this type of method is seldom used.

5.2.2 Operational Modes

Two operational modes, continuous and periodic, are possible with pipeline system leak detection and inspection methods. Generally, maximum effectiveness is obtained when both modes are implemented. In some instances, this approach can be used to provide dual inspections or leak checks and result in an increase in the overall system reliability and effectiveness.

5.2.2.1 Continuous Monitoring--

Ideally, continuous monitoring for leaks is the most effective way of reducing the volume of spillage, although not necessarily the most cost-effective or practical. Most leakage volume occurs from a small number of large spills (see Section 4.6.2). Continuous monitoring could immediately detect and locate these large spills and shut the system down, thus minimizing the volume of oil spilled. A few continuous monitoring methods could also provide incipient failure detection and thus prevent a potentially large spill from occurring.

Continuous monitoring systems currently used on modern lines are seriously limited. Only high spill-discharge rates and large spill volumes can be detected. Also, leak location is either inaccurate or cannot be done. One modern continuous leak monitoring methods, for example, consists of metering the input and output volume of the pipeline and continuously comparing the readings. When there occur significant differences in these meter readings that cannot be accounted for, a leak is suspected. There are a number of normal reasons for variance in these readings, such as temperature, meter errors, flow changes, etc., that can be of the same magnitude and duration as a leak. Thus, there is difficulty in distinguishing between a small-to-medium leak and a normal fluid variance. Other commonly used continuous methods with similar limitations are pressure deviations and flow rate comparisons. A few continuous monitoring methods which are state-of-the-art or in the development or feasibility stage have fewer potential limitations. The mathematical modeling method, for example, accounts most normal variance and potentially can be an order of magnitude more sensitive than most modern methods, i.e., volume comparison, etc., in use today.

EPA Form 2350-4 (4-80)
TYPING GUIDE SHEET

5.2.2.2 Periodic Monitoring-Scheduled Inspections--

A scheduled inspection program using periodic monitoring methods potentially can be a cost-effective way of adequately maintaining pipelines. Many periodic leak detection and inspection methods are particularly effective in detecting small leakage rates or small internal defects that may result in a leak. Pressure difference leak detection, for example, can detect leakage rates to about 3 gal/hour. Periodic inspection of the pipeline with an electromagnetic inspection pig may be quite effective in checking the line for internal damage and corrosion before a leak actually occurs. Scheduled use of these and other methods may reduce significantly the frequency and volume of leaks. The main disadvantage of using only a scheduled periodic inspection program is that it provides no leak detection between inspections and this could potentially allow huge volumes of petroleum spillage to occur before detection.

5.2.3 Applications and Operating Conditions--Scope

The scope of this study is to investigate the capability of leak detection and inspection methods to adequately control accidental spills from new or existing operational pipeline systems by implementing periodic inspections and/or continuous monitoring. Essentially all pipeline system operating conditions are expected to be available for implementation of these methods. This would include normal operations or special conditions for inspections such as shutdown of pipeline, filling and pressurization with foreign gases or liquids.

Some of these methods may also apply for initial testing of new installations. A few of these methods could be effective in quality control prior to construction phase or during construction. Specific guidelines or recommendations for these applications are beyond the scope of the study. It is assumed that new pipeline system components will be inspected for defects, tested and qualified by the manufacturer prior to installation. Furthermore, it is intended that these leak detection and inspection methods will not replace, or be used instead of, inspections currely required by existing government regulations[7] (see Section 5.4.1).

5.2.4 Uses

The primary use of these methods is to reduce the risk of oil spills, i.e., frequency and volume of spills from the pipeline system. High risks of oil spills from pipeline system components generally exist for older, small diameter pipelines because of frequent spills or from large diameter or underwater pipelines because of large volume oil spills. Implementation of effective and practical leak detection and inspection methods potentially can reduce these risks or oil spillage.

5.2.4.1 Reduce Frequency of Spills--

Periodic and/or continuous inspections to check the performance and condition of system components can result in a reduction in the frequency of spills. The purpose is to detect a condition that may lead to a leak so that suitable repairs or replacements can be made before a leak can occur. Detection would involve inspection for either insignificantly small leaks, such as an oil drip, or internal defects that may lead to failure. Detection would consist of examination of a particular component with one or more inspection instruments. Then, based on a previously established criteria, the suitability for continued service, repair or replacement would be determined. Samples would include the periodic pigging of the line to check the condition of welds, seams, corrosion, cracks, etc. Continuous inspection might be accomplished with an acoustic array to detect either acoustic emissions generated from internal defects in a pipeline or external pipeline impacts from outside forces.

5.2.4.2 Reduce Volume of Spills--

Continuous and/or frequent implementation of leak detection and inspections provide the potential of quickly detecting and locating a leak so that the spill can be shut off, thereby minimizing the volume spilled. For this purpose, continuous monitoring leak detection might include comparison of flows, pressures, volumes, etc., at both ends of the line while frequent periodic inspection might include daily visual observation of offshore lines.

5.2.5 Installation

Leak detection equipment can be installed in, on, or external to the pipeline system. Essentially all installation schemes are considered in this study. For analysis purposes, installation is separated into four main categories and briefly described in the subsections that follow.

5.2.5.1 Non-Interference with Pipeline Operation--

Ideally, leak detection methods that do not interfere with pipeline operations are considered to be most desirable. However, these methods generally are ineffective. For example, the two most common methods are line walking and over and short accounting. Both are ineffective in early detection of major oil spill incidents or prevention of leaks.

5.2.5.2 Limited Interference with Pipeline Operations--

Methods that cause limited interference with pipeline operations are considered here as those that require temporary shutdown of the pipeline or affect throughput. This would include methods such as inspection pigs, continuous monitoring using equipment at each end of the line, mathematical modeling, and most pressure testing schemes. Methods causing limited interference are considered to involve only nominal costs. Furthermore, such methods may be quite effective in preventing leaks.

5.2.5.3 Retrofitting--

Methods which require retrofitting require substantial line modifications and/or long-term shutdown. The necessity to uncover a significant portion of the line to install a detector system or to provide equipment and power at a number of remote unmanned locations would be considered a retrofit. Pressure difference methods would be considered in this category because a number of closely spaced block valves with controls and sensor/transmitter units are required.

Depending upon specific use of a particular method, installation might be considered a retrofit or limited interference with the line. For example, a passive acoustic array system for detecting leaks and/or internal pipeline damage requires retrofit installation consisting of a number of closely spaced transducers installed along the line. However, an acoustic array system to detect outside damage may allow large spacing between detectors and require only limited interference with the line.

5.2.5.4 New Pipeline--

Installation of a leak detection and inspection system on a new line generally can be done with minimal cost and no interference during the construction phase. Also, modern pipeline systems are usually computer-controlled with a number of remote monitoring stations and automatically controlled equipment. Thus, equipment and installation for most leak detection and inspection may require only nominal additions to existing equipment. Some methods may be cost-feasible for new lines, while prohibitive installation and equipment costs for existing lines would render many of these same methods unacceptable.

5.3 COMPENDIUM OF LEAK DETECTION AND INSPECTION METHODS

Most basic principles such as acoustic, ultrasonic, electromagnetic, nuclear, and optical can be applied by various methods or detecting and preventing pipeline system leaks. A wide variety of applicable petroleum pipeline leak detection and inspection methods exist that employ equipment and detectors that are commercially available, in the engineering stage, or in the feasibility/developmental stage. For completeness, applicable methods, including many that are based on the same principle but involve slightly different techniques, are identified and briefly compared in this section. Only a limited number of methods are expected to be effective in significantly reducing either the frequency or volume of spills. However, many methods may be quite effective for particular lines or specific pipeline system components and may, if implemented, prevent a pollution incident. Thus, all applicable methods are included.

Most leaks from pipeline systems occur from buried onland and underwater pipelines (see Section 4.6.2). Hence, leak detection methods are geared to this problem.

In general, greatest risk of a serious pollution incident exists for lines in or near water. This is true, even though the spill incidence rate for underwater lines is similar to onland. A spill at or near water usually causes a much greater pollution problem because the oil can be spread over large areas, and costs such as those required for cleanup are high. Thus, a number of leak detection and inspection methods are included specifically for lines in or near water.

Methods primarily intended for use at marine terminals and offshore production platforms are also considered. Although fewer spills and lower spill rates typically occur at these locations than onland, each individual spill is usually much more serious.

5.3.1 Identification

A summary of all applicable leak detection and inspection methods are listed on page 157. Methods are separated into two types in the list presented on page 158. A summary that combines operational monitoring modes and types is shown in Table 45.

5.3.2 Description and Comparison

Leak detection and inspection methods are described and compared in Tables 46 through 55. Each method is included in one of ten categories[a]. Additional details on methods selected for further analysis are given in Appendix E. Section 7 supplies pertinent information on cost and equipment.

5.3.2.1 Visual and Aided Visual Line Observations--

Visual inspections for petroleum pipeline systems are given in Table 46. These inspections do not interfere with line operations and are carried out in a number of ways: oneland - by walking, driving or flying the line; on water at marine terminals or pumping platforms - by inspection in a launch or an inspector located on the deck of the ship or pumping platform; or underwater - by divers or submersibles (manned or remote). For most lines, some form of periodic visual observation is required by U.S. Government regulations.

Visual line observation, by line walking, was the earliest form of leak detection and inspection. Even today, it is the main method of detecting pipeline system leaks. However, lower cost techniques such as visual inspection from a light plane or truck have replaced actual walking of the line. Simple line observation is considered by some to be the most practical way of detecting small pinhole-size leaks.

Serious limitations exist for the visual inspections currently carried out in the U.S. The most critical limtiations are:

- Pipeline faults resulting in leaks can be detected only after a leak occurs and the oil surfaces.
- Leaks between the periodic line observations are not detected.
- There is only minimal protection against damage from outside forces.

---

[a] In certain cases, leak detection and inspection methods might be applicable to more than one category. To avoid duplication, the information is presented in only one main category.

INSPECTION AND LEAK DETECTION METHODS FOR PETROLEUM PIPELINES[a]

1. Visual and Aided Visual Line Observations

(a) Line walking, aircraft
(b) From launch
(b) On deck of ship
(b) On terminal or pumping platform
(c) Submersible
(c) Diver
Visual aids
  (c) Hydrocarbon probe
  (c) Remote oil spill detectors
  (d) Ultraviolet light source
  (c) TV monitor
  (c) Tape detection

2. Oil Spill Detectors on or Near the Water

(c) Portable--on launch or ship
(c) Stationary--at marine terminals or on pumping platform
(c) Land type--across rivers and channels or coastline
Buoy type

3. Internal Fluid Variations During Transfer

(b) Pressure deviation
(b) Volume comparison
(b) Flow rate comparison
(b) Flow rate deviation
(b) Over and short
(c) Mathematical modeling
(c) BS&W deviation
(d) Pressure difference with reference and threshold
(d) Fluid mass deviations
(c) Negative surge
(c) Inspection pig--passive ultrasonic
(d) Pressure fluctuation levels
(c) Production surveillance monitor

4. Detection and Location of Leaked Oil on or at a Short Distance from Pipeline

(d) Shroud with EMP pulsed coaxial cable
(e) Continuous thermistor
(e) Tape detection
(e) Oil soluble tubing
(c) Hydrocarbon probe
(c) Double walled pipe
(c) Seal leak detector--capacitor type
(c) Nuclear tracers
(c) Nitrous oxide injection
(d) Acoustic/sonar
(d) Acoustic underwater
(e) Laser detection--underwater
(d) Passive ultrasonics
(c) External rods with acoustic sensors
(d) Passive acoustic array--leaks

5. Periodic Pressure Tests

(b) Pressure-static
(b) Hydrostatic
(b) Pressure difference
(c) Dye tracing
(c) Seal leak detector--joint type
(d) External hydrostatic
(c) Seal leak detector--thermistor type
(d) Reflected pressure wave
(d) Acoustic resonance
(c) Passive acoustic array
  Acoustic emission

6. Corrosion Inspection

(c) Corrosion flow sampling
(b) Corrosion metering--internal
(b) Corrosion metering--external
(b) Holiday detector
(b) Visual corrosion
See also NDT
See also inspection pigs

7. Standard Non-Destructive Inspection

(b) Active ultrasonics
(a) X-ray
(b) Gamma ray, radioactive isotopes
(d) Magnetic rubber, foil, tape
(d) Ultrasonic imaging
(b) Eddy current
(b) Penetrants

(b) 8. Inspection Pigs

9. Survey--Pipeline System Charting and Depth of Burial

(b) On land--radar
Underwater
  (b) Sonar--sidescan
  (b) Sonar--sub-bottom profiling
  (b) Microwave position system
  (b) Scour
  (b) Pneumofathometer

10. Miscellaneous

(d) Passive acoustic array for outside forces
(c) Passive acoustics for machinery damage
(b) Liquid level sensor
(e) Laser holographic interferometry
(c) Magnetic chip
(b) Control room monitoring, alarms shut-off
(b) Oil odor
(e) Thermal or infrared
(e) Thermal paint
(e) Microwave
(e) Filtered particle
(c) Sonic

---

[a] Status of methods for line pipe:
(a) Required by U.S. regulations
(b) Common use
(c) State-of-the-art
(d) Developmental
(e) Feasibility

TYPE OF LEAK DETECTION AND INSPECTION METHODS

FLUID LEAK DETECTION

- Visual
  - Line walking, truck, aircraft
  - From launch
  - On deck of ship
  - On terminal or pumping platform
  - Submersible
  - Diver
- Visual Aids
  - Hydrocarbon probe
  - Remote oil spill detectors
  - Ultraviolet light source
  - TV monitor
  - Tape detection
- Oil spill detectors on or near the water
- Pressure deviation
- Volume comparison
- Flow rate comparison
- Flow rate deviation
- Over and short
- Mathematical modeling
- BS&W deviation
- Pressure difference with reference and threshold
- Fluid mass deviation
- Negative surge
- Inspection pig--passive ultrasonic
- Pressure fluctuation levels
- Production surveillance monitor
- Shroud with EMP pulsed coaxial cable
- Continuous thermistor
- Tape detection
- Oil soluble tubing
- Hydrocarbon probe
- Double walled pipe
- Seal leak detector--capacitor type
- Nuclear tracers
- Nitrous oxide injection
- Acoustic/sonar
- Acoustic underwater
- Laser detection-underwater
- Passive ultrasonics
- External rods with acoustic sensors
- Passive acoustic array--probe
- Pressure-static
- Hydrostatic
- Pressure difference
- Dye tracing
- Seal leak detector-joint type
- External hydrostatic
- Seal leak detector-thermistor type
- Reflected pressure wave
- Acoustic resonance
- Passive acoustic array
  - Acoustic emission
- Liquid level sensor
- Control room monitoring, alarms, shut-off
- Thermal or infrared
- Oil odor

INCIPIENT FAILURE DETECTION

- Passive acoustic array-acoustic emission
- Reflected pressure wave
- Acoustic resonance
- Corrosion flow sampling
- Corrosion metering-internal
- Corrosion metering-external
- Holiday detector
- Active ultrasonics
- X-ray
- Gamma ray, radioactive isotopes
- Magnetic particle
- Magnetic rubber, foil or tape
- Ultrasonic imaging
- Eddy current
- Penetrants
- Inspection pigs
- Radar
- Sonar-sidescan
- Sonar-sub-bottom profiling
- Microwave position system
- Scour
- Pneumofathometer
- Passive acoustic array for outside forces
- Passive acoustics for machinery damage
- Laser holographic interferometry
- Magnetic chip
- Thermal point
- Microwave
- Filtered particle
- Sonic

TABLE 45. SUMMARY OF TYPE AND OPERATIONAL MODE OF LEAK DETECTION AND INSPECTION METHODS

Periodic Monitoring--Scheduled Inspections

Fluid Leaks

- Visual and Aided Visual Line Observations
  - Line walking, truck, aircraft
  - From launch
  - On deck of ship
  - On terminal or pumping platform
  - Submersible
  - Diver
  - Visual aids
    - Hydrocarbon probe
    - Remote oil spill detectors
    - Ultraviolet light source
    - Tape detection
- Internal Fluid Variations
  - BS&W deviation
  - Over and short
  - Inspection pig-passive ultrasonic
- Detection and Location of Leaked Oil on or at a Short Distance from Pipeline
  - Hydrocarbon probe
  - Nuclear tracer
  - Nitrous oxide injection
  - Passive ultrasonics
  - Acoustic/sonar
  - Acoustic-underwater
  - External rods with acoustic sensors
- Periodic Pressure Tests
  - Pressure-static
  - Hydrostatic
  - Pressure difference
  - Dye tracing
  - Seal leak detector-joint type
  - External hydrostatic
  - Seal leak detector-thermistor type
  - Reflected pressure wave
  - Acoustic resonance
  - Passive acoustic array
    - Acoustic emission
- Miscellaneous
  - Oil odor
  - Thermal or infrared
  - Thermal paint

Incipient Failure Detection

- Detection and Location of Leaked Oil on or at a Short Distance from Pipeline
  - Passive acoustic array
    - Acoustic emission
- Periodic Pressure Tests
  - Reflected pressure wave
  - Acoustic resonance
  - Passive acoustic array
    - Acoustic emission
- Corrosion Inspection
  - Corrosion metering-external
  - Holiday detector
  - Visual corrosion
  - See also NDI
  - See also inspection pigs
- Standard Non-Destructive Inspection
  - Active ultrasonics
  - X-ray
  - Gamma ray, radioactive isotopes
  - Magnetic particle
  - Magnetic rubber, foil, tape
  - Ultrasonic imaging
  - Eddy current
  - Penetrants
- Inspection Pigs
- Survey-Pipeline System Charting and Depth of Burial
  - Onland-radar
  - Underwater
    - Sonar-sidescan
    - Sonar-sub-bottom profiling
    - Microwave position system
    - Scour
    - Pneumofathometer
- Miscellaneous
  - Laser holographic interferometry
  - Filtered particle
  - Sonic

(continued)

EPA Form 2350-4 (4-80)
TYPING GUIDE SHEET

TABLE 45 (continued)

Continuous Monitoring

Fluid Leaks

- Visual and Aided Visual Line Observations

  TV monitor

- Oil Spill Detectors on or Near the Water

  Portable-on launch or ship
  Stationary-at marine terminals or on pumping platform
  Buoy type
  Onland type-across rivers and channels or coastlines

- Internal Fluid Variations During Transfer

  Pressure deviation
  Volume comparison
  Flow rate comparison
  Mathematical modeling
  Pressure difference with reference and threshold
  Fluid mass deviations
  Negative surge
  Pressure fluctuation levels
  Production surveillance monitor

- Detection and Location of Leaked Oil on or at a Short Distance from Pipeline

  Shroud with EMP pulsed coaxial cable
  Continuous thermistor
  Tape detection
  Oil soluble tubing
  Double walled pipe
  Seal leak detector-capacitor type
  Laser detection-underwater
  Passive acoustic array-probe

- Miscellaneous

  Liquid level sensor
  Control room monitors, alarms, shut-off

Incipient Failure Detection

- Detection and Location of Leaked Oil on or at a Short Distance from Pipeline

  Passive acoustic array-acoustic emission

- Corrosion Inspection

  Corrosion flow sampling
  Corrosion metering-internal

- Miscellaneous

  Passive acoustic array for outside forces
  Passive acoustic array for machinery damage
  Magnetic chip

EPA Form 2250-4 (4-80)
TYPING GUIDE SHEET

TABLE 46. VISUAL AND AIDED VISUAL LINE OBSERVATIONS

Method[a]	Defects Measured	Sensitivity[b]	Advantages[c]	Disadvantages
VISUAL LINE OBSERVATIONS				
(a) By Walking, Plane, Truck	1. Oil leaks 2. Outside damage	1. Minor spills	1. Simple 2. Reduces possibility of damage by outside forces 3. Practical for minor leaks	1. High cost 2. No leak detection between inspections 3. Subject to personnel error
(b) From Launch-Patrolling Lines (Undersea or underwater pipelines.)	1. Oil leaks	1. Minor spill	1. Simple 2. Practical for minor leaks	1. Medium cost 2. Cannot be carried out in bad weather 3. Not adequate in darkness 4. Subject to personnel error 5. Difficulty in discriminating between an oil spill and the oil sheen from boat engines or a few liters of oil leakage at a ship (this may cause sheen over a wide area.)
(c) From Launch at Marine Terminal or Offshore Production Platform	1. Oil leaks 2. Component external damage	1. Catastrophic failures-early detection 2. Small spills on water 3. Minor underwater spills 4. Mooring system failures	1. Simple	1. Medium cost 2. Cannot be carried out in bad weather 3. Subject to personnel error 4. Difficulty in discriminating between an oil spill and the oil sheen from boat engines
(d) On Deck of Ship at Marine Terminal (Mooring systems oil transfer system components-piping, hoses, valves, etc.)	1. Oil leaks 2. Some external defects on marine hoses 3. Orientation, alignment, movement problems that can cause failure 4. Mooring system failures at ship 5. Transfer system failures	1. Catastrophic failures-early detection 2. Minor spills	1. Simple 2. Good for shipboard connections 3. Practical	1. Inadequate in bad fog or in darkness except for ship breakout 2. Subject to personnel error 3. Difficulty in discriminating between minor spills and thin oil sheen on surface of water 4. Medium cost
(e) On Pumping Platform or Marine Terminal (Platform, pipeline, etc.)	1. Oil leaks 2. External piping (riser) damage	1. Minor to medium spills	1. Simple	1. Difficult to discriminate between thick oil spills and thin oil sheen on surface of water 2. High cost
(f) Submersible-Manned or Remote Contolled (Pipeline, pumping platform support structure.)	1. Oil leaks 2. Leaks or defects in underwater pipeline 3. Platform structure damage	1. Medium to major spills	1. Particularly useful if defect or failure is expected based on other inspections or if a major earthquake occurs 2. Fast inspections over wide area	1. High cost
(g) Diver or Scuba Diver[37] (Platform, pipeline, etc.)	1. Oil leaks 2. External physical defects 3. Orientation, alignment and movement problems that can cause failure	1. Minor spills 2. Small oil leaks	1. Underwater inspection	1. Medium cost 2. Inspection frequency is limited 3. Cannot be used in fog, darkness and rough water 4. Subject to personnel error 5. Photographic records and video tape records sometimes unreliable or difficult to interpret
AIDED VISUAL				
(h) Line Walking-Inspector with Hydrocarbon Detector	1. Oil leaks on land	1. Small spills	1. Detects leaks that may not surface for long periods of time 2. Low cost	

(continued)

TABLE 46 (continued)

Method[a]	Defects Measured	Sensitivity[b]	Advantages[c]	Disadvantages
(j) Remote Oil Spill Detectors Plane With Oil Spill Detectors[58,59] Sidelooking Airborne Detectors, Passive Microwave Imager, Camera, Forward Looking Radar, Infrared	1. Oil spills on land or water	1. Small spills	1. Less subject to personnel error and much more sensitive than visual observations only	1. High cost
(k) Man on Deck of Ship at Marine Terminal at Night with Visual Inspection but Using Ultraviolet Light Source	1. Oil leaks on water	1. Ultraviolet light causes oil to fluoresce which enhances visual inspection	1. Simple 2. Aids visual inspection 3. Low cost	
(l) TV Monitor on Ship-Low Light TV Camera (Broad coverage of marine hoses, other oil transfer system components and mooring system.)	1. Oil leaks 2. Orientation, alignment and movement problems that can cause failure 3. Ship breakout	1. Catastrophic failure-early detection 2. Small or minor spills	1. Simple 2. Wide area of coverage 3. Operates at light levels inadequate for visual inspection 4. Commercially available 5. Aids visual inspection on deck of ship	1. Inadequate in fog, bad weather or darkness
(m) TV Monitor on Pumping Platform-Low Light TV Camera (Broad coverage of platform, pipeline, ship movement, etc.)	1. Oil leaks	1. Minor spills	1. Simple 2. Wide area of coverage 3. Operates at light levels inadequate for visual inspection 4. Commercially available 5. Low cost	1. Inadequate in fog, bad weather or darkness
(n) Tape Detection[60] (Tape wrapped around hose, flange, etc. leaked oil will change color where it comes into contact with oil.)	1. Oil leaks	1. Small spills	1. Simple 2. Good incipient failure detection 3. Can be used for continuous inspection 4. Can be used underwater	1. Not rugged 2. Feasibility/development stage 3. High-cost

[a] Identifies Reference number

[b] Small spill <2,100 gal. (50 barrels); Minor spill 10,000 gal. (238 barrels); Medium spill 10,000 to 100,000 gal; Major spill >100,000 gal.

[c] Very rough estimate of inspection costs for year for components that would typically be inspected: Low cost 0 - $20K; Medium cost $20K to $200K; High cost >$200K.

TABLE 47. OIL SPILL DETECTORS ON OR NEAR THE WATER

Method[a]	Defects Measured	Sensitivity[b]	Advantages[c]	Disadvantages
OIL SPILL DETECTORS[14,61] (Continuous Monitoring)				
(a) On-Boat-Infrared Type (Infrared type point sensor. Transmitter projects an infrared light beam to surface of water and reflected infrared light is analyzed by receiver. An alarm is activated when oil is detected.)	1. Oil spills on water	1. Device has been proven in USCG tests to detect oil spills in rough water 2. Monitors a small area typically less than a square foot	1. Simple 2. Low cost 3. Reduces dependence on visual inspection 4. Some commercial instruments can discriminate between thick film and on oil sheen. This is difficult to interpret by visual inspection 5. Some commercial devices are explosion proof certified	1. Currently not used on boats However, a few oil terminals in Europe are considering purchase of such devices 2. Alignment may be a problem in very rough weather 3. Monitors a small area typically less than a square foot
(b) On Deck of Ship-Infrared (Operation same as for on a boat except devices must be battery powered, portable and satisfy explosion proof regulations.)	1. Oil spills on water	1. Located at bow of ship 2. Can work at height of about 30 meters	1. Simple 2. Medium cost 3. Works in fog 4. Aids visual inspections. Useful at night.	1. No commercial version exists for use on deck of ship but this might be available in the near future 2. Medium development funding required for ship mounted version 3. Device must meet explosion certification 4. Detector may not see oil leaks under certain conditions, i.e., tide can go in one direction and wind in another direction 5. Requires a relatively stable platform for a spot type sensor 6. Sensor must allow for changes in draft of ship
(c) At Marine Terminals or on Platform-Infrared Type(d) (See operation for on a boat.)	1. Oil spills on water		1. Simple 2. Low cost 3. Works in fog 4. Commercially available 5. Aids visual inspection	1. Requires about 4 sensors on platforms or at terminal
(d) At Marine Terminals or on Platform Fluorescent (Scanning fluorescense type sensor but operation similar to infrared type.)	1. Oil leaks on water at night	1. 600 to 1000-foot range	1. Works well at night 2. Medium cost 3. Commercially available 4. Aids visual inspection	1. No daylight operation

(continued)

TABLE 47 (continued)

Method[a]	Defects Measured	Sensitivity[b]	Advantages[c]	Disadvantages
(e) On Buoy-Infrared (Infrared type point sensor. Transmitter projects a light beam to surface of water and reflected infrared light is analyzed by a receiver. An alarm is activated when oil detected.)	1. Oil spills on water	1. Small area	1. Simple 2. Low cost	1. No commercial version available
(f) On Buoy-Scanning Infrared	1. Oil leaks on water	1. Wide range around buoy	1. May require only one sensor	1. Feasibility stage only 2. Medium cost 3. Range uncertain at this time 4. Complex
(g) Buoy Type (In Situ) Membrane Type-Thermal Conductivity (Device floats near the component and separates oil from water by a permeable membrane. Device senses presence of small quantity of oil through self heated sensor that responds to differences in thermal conductivity between air and oil.)	1. Oil leaks on water	1. Range about 1 meter	1. Simple 2. Low cost	1. No commercial version available 2. Would require an array to be very effective 3. Must provide safe, explosion-proof operation under severe environment or external impacts
(h) Buoy Type (In Situ) Ultraviolet (Works on ultraviolet detection principle.)	1. Oil leaks in water	1. Range about 1 meter	1. Simple 2. Low cost	1. Does not work well in daytime 2. No commercial version available 3. Usually requires an array of sensors to be very effective 4. Must be explosion proof
(i) Buoy Type (In Situ) Infrared (See operation for in a boat.)	1. Oil leaks on water	1. Range about 1 meter	1. Simple 2. Low cost	1. No commercial version available 2. Usually requires a variety of sensors to be effective 3. Must be explosion proof
(j) Across Channels and Rivers-Bistatic Active Infrared[d] (Infrared transmitter and receiver located on tall towers across river or channel. Device detects hydrocarbons on water along narrow path at distances to 900 feet.)	1. Hydrocarbons on water	1. Range about 900 feet		1. Water must have wavy surface 2. Medium cost 3. Feasibility/developmental stage
(k) Laser Detection-On Water Oil Leaks (Laser placed on high land. System traverses fixed plane along pipeline or hose string. Since laser absorption by oil and water is known, a leak can be detected.)	1. Oil leaks	1. Depends on laser source and power, detector sensitivity and traverse 2. Minor or medium spill sensitivity expected	1. Can be used above water, on shore, on platform or on deck of ship 2. Continuous monitoring	1. High cost 2. Requires trained personnel 3. Affected by bad weather 4. Detects leaks only after they occur and oil rises to the surface 5. Developmental stage

[a] Identifies Reference number.

[b] Small spill < 2,100 gal (50 barrels); minor spill 10,000 gal (238 barrels); medium spill 10,000 to 100,000 gal; major spill > 1000,000 gal.

[c] Very rough estimate of inspection costs for components that would typically be inspected; low cost 0 - $20K; medium cost $20K to $200K; high cost > $200K.

[d] Note: Many oil companies are currently using these devices at supertanker terminals for oil spill detection; usually installed on piling

TABLE 48. INTERNAL FLUID VARIATIONS DURING TRANSFER

Method[a]	Defects Measured	Sensitivity[b]	Advantages[c]	Disadvantages
(a) Pressure Deviation Continuous (Monitor of line pressures at various locations along pipeline. If pressure deviations exceed a set point value, a leak is assumed.)	1. Oil leaks	1. Major oil leaks 2. Accuracy: 1-5%	1. Low cost 2. Simple 3. Commonly used 4. Commercially available 5. Continuous monitoring 6. Work well for large leaks close to pumping station	1. Catastrophic failure only 2. Cannot detect small leaks or large leaks a long distance from pump station 3. Affected by changes in fluid properties, input and output tank heads, lines with changing flows, etc.
(b) Volume Compadison (Flow Quantity) Continuous (Volume comparison based on time intervals of several minutes duration to check metered barrels into pipeline against metered volume out. Comparison of volume measurements typically occur over hourly periods. This can be considered as a fast over and short)	1. Oil leaks	1. Medium or major oil leaks 2. Large leaks over a short period of time and small leaks over a long period of time 3. Accuracy: 0.2 to 3%	1. Simple 2. Commercially available 3. Continuous monitoring	1. Detects leaks after they occur 2. Difficult to detect slow leaks that over a period of time may result in a major oil spill 3. Cannot detect a catastrophic failure in sufficient time to prevent major oil spill 4. Tendency by operators to raise set-points to reduce alarms because of line pack and other considerations 5. Detects leak only once per hour for most commonly used systems 6. Medium cost
(c) Flow Rate Comparison Continuous (Flow rate measurements at each end of the pipeline section are compared. Large differences in measurements indicate possibility of leakage.)	1. Oil leaks	1. Major oil spills 2. Accuracy: 1-5%	1. Simple 2. Detects catastrophic failure 3. Commercially available 4. Commonly used 5. Continuous monitoring	1. Poor leak detection 2. Tendency by operators to raise setpoints to reduce alarms and thus decrease leak sensitivity 3. Detects leaks after they occur 4. Does not respond to steady state or slowly varying leaks 5. Will give warning of large leak only during the time the line dynamics change
(d) Flow Rate Devations 1-5% 1-5% Accuracy (Deviation in flow rates are measured at specific flow stations. If the change in flow exceeds a certain value, i.e., 1 to 5 percent, an alarm is sounded.)	1. Oil leaks	1. Major oil spills 2. Accuracy 2-5%	1. Low cost 2. Commercially available 3. Continuous monitoring 4. Commonly used 5. Detects catastrophic failures	1. Poor leak detection 2. Tendency by operators to raise setpoints to reduce alarms and thus decrease leak sensitivity 3. Detects leaks after they occur
(e) Over and Short-Accounting (Difference between barrels received into and delivered out of pipeline system and correction for inventory changes and temperature. Typically carried out weekly to monthly intervals.)	1. Oil leaks	1. Very small leaks that exist for long period of time-months to years-0.1 to 0.2% of throughput	1. Minimal cost 2. Part of normal accounting 3. Commonly used 4. Useful for small leaks	1. Defects possibility of leaks only after long periods of time

(continued)

TABLE 48 (continued)

Method[a]	Defects Measured	Sensitivity[b]	Advantages[c]	Disadvantages
(f) Mathematical Modeling Continuous ≈ 0.1% Accuracy (Computerized method of modeling pipeline system (components, sizes, materials, etc.) and flow characteristics (temp., pressure, viscosity, etc.) to optimize leak sensitivity.)	1. Oil leak	1. Detects ≈ .1% of actual flow rate 2. Small to medium leaks 3. Detects leaks when flow reaches flow meters	1. Low cost 2. Computerized reduction 3. Good failure detection 4. Provides leak detection improvements over conventional hydrostatic pressure tests	1. Medium cost if transducers must be added to existing supervisory control system 2. May require trained personnel to properly interpret data or maintain system
(g) BS&W Metering (Periodic samples of petroleum are taken at each end of the line. Collective samples are put in a centrifuge and bottom sediment and water content is determined.)	1. Oil leaks 2. Leaks in underwater pipelines 3. Volumetric errors	1. Medium leaks 2. Less accurate than volume comparison 3. BS&W cannot be read to better than 0.1% increments or 10% of typical full scale	1. Simple 2. Provides check of gross volumetric leak detectors 3. Commonly used	1. Inaccurate 2. Medium cost
(h) Pressure Difference with Reference and Threshold[52] (Continuously comparing the pressure difference between the differential pressure in the pipeline and a reference pressure and a predetermined threshold pressure. The threshold pressure is the line pressure at the start of each cycle of comparison.)	1. Oil leaks	1. Unknown	1. Low cost 2. Computerized reductions 3. Can be used in conjunction with supervisory control system 4. Continuous monitoring	1. Insufficient information available on actual on-line performance

(continued)

TABLE 48 (continued)

Method[a]	Defects Measured	Sensitivity[b]	Advantages[c]	Disadvantages
(i) Mass Deviations	1. Oil leaks	1. Unknown	1. Eliminates errors from both pressure and temperature	1. Not commonly done
(j) Negative Surge-(Leak Pressure Wave Detection) (Large rupture type leak causes negative pressure wave to travel along pipeline that can be detected and located.)	1. Oil leaks	1. Leakage > 600 barrels per hour 2. Leak location within 2 miles	1. Continuous inspection 2. Commercially available 3. Supplements other methods 4. Continuous monitoring 5. Instantaneous leak detection and location	1. Negative surges caused by other pipeline operations must be accounted for
(k) Inspection Pig-Passive Ultrasonic Type (An escaping fluid from a pipeline leak emits sounds. A passive ultrasonic detector, mounted in an oil tight container, detects the leak.)	1. Leak from hairline cracks or small corrosion holes	1. 3 to 5 gallons per hour leaks	1. Locates leak within a few feet 2. Should work well if a leak detector pig is built and dedicated for a specific pipeline	1. High cost 2. Not commercially available in the U.S. because of difficulty in applying device to a variety of pipelines 3. Requires some development for reliable results 4. Background noise currently limits leak resolution
(l) Pressure Fluctuation Levels Continuous (Large leaks cause large increases of pressure fluctuation over a certain frequency band at the leak location. These fluctuations are travelling along the pipeline. They are detected by pressure sensors with the sensing element in contact with the flow. Sensors are located many miles apart.)	1. Large oil leaks	1. Unknown 2. Background noise may seriously limit sensitivity	1. Simple 2. Low cost 3. Rapid detection of leak 4. Supplements other leak detection	1. Method currently in the feasibility stage
(m) Production Surveillance Monitor (A dynamic pressure transducer measures small pressure fluctuations that relate directly to liquid flow rate-for oil production two-phase flow.)	1. Large oil leaks 2. Anomalous changes or well problems	1. About 10%	1. Proven in field use 2. Low cost 3. Can be continuous monitoring 4. Useful for two-phase flow	

[a] Identifies Reference number

[b] Small spill <2,100 gal. (50 barrels); Minor spill <2,000 gal. (50 barrels); Medium spill 10,000 to 100,000 gal; Major spill >100,000 gal.

[c] Very rough estimate of inspection costs for year for components that would typically be inspected:
Low cost 0 - $20K; Medium cost $20K to $200K; High cost >$200K.

TABLE 49. DETECTION AND LOCATION OF LEAKED OIL ON OR AT A SHORT DISTANCE FROM PIPELINE

Method[a]	Defects Measured	Sensitivity[b]	Advantages[c]	Disadvantages
LEAKED OIL				
(a) Shroud With EMP Pulsed Coaxial Cable (A shroud is placed above or around pipeline to collect oil from a leak. A special continuous coaxial cable would have breaks in the outer cover. An electromagnetic pulse would be sent down the cable and pass through entire length of cable and with a short circuit electrical terminations be reflected back (inverted) to the send end. An oil leak would cause the reflected wave to be sent back noninverted.)	1. Oil leaks	1. Minor spills 2. Minute leaks can be detected and then located within a few feet	1. Simple 2. Continuous monitoring 3. Good incipient failure detection 4. Can be used with supervisory control system	1. Unproven 2. Reliability uncertain 3. Detects leaks after they occur 4. Medium cost
(b) Continuous Thermistor (Device installed on outside and along the pipe. Oil leaks change the properties of the continuous thermistor type cable.)	1. Oil leaks	1. Unknown	1. Continuous monitoring	1. Medium cost 2. Feasibility stage
(c) Tape Detection (Tape wrapped around pipeline leaked oil will change tape electrical characteristics.)	1. Oil leaks	1. Minor spills	1. Simple 2. Good incipient failure detection 3. Can be used for continuous operation	1. Not rugged 2. Feasibility/development stage 3. High cost
(d) Oil Soluble Tubing (Oil soluble tubing is wrapped around the line, covered with a loose jacket and filled with liquid under pressure. Loss of pressure indicates a leak.)	1. Oil leak	1. Small spills	1. Simple	1. System did not work on Trans-Alpine Pipeline
(e) Hydrocarbon Probe (Sniffer) (Hydrocarbon probe is installed in towfish and towed a few feet above the pipeline. Probe detects hydrocarbons from oil leaks. A pressure sensor in towfish measures depth.)	1. Oil leaks in pipeline 2. Oil that may settle on the bottom	1. 5×10^{-9} ml gas per ml water	1. Simple 2. Low cost 3. Commercially available 4. Good incipient failure detection 5. Provides continuous record	
(f) Double Walled Pipe (Requires double walled pipe with the one transferring fluid to be centered inside the other. A variety of adequate oil detectors could be installed on the inside of the outer pipe to detect leaks from the inner pipe.)	1. Oil leaks	1. Small or minor leaks 2. More sensitive than any other method for pipelines	1. Simple 2. Excellent incipient failure detection 3. Continuous inspection 4. Contains the leaked oil thus preventing spill 5. Cost effective for short sections of pipeline located at potential leak areas	1. Very high cost

(continued)

TABLE 49 (continued)

Method[a]	Defects Measured	Sensitivity[b]	Advantages[c]	Disadvantages
(g) Seal Leak Detector Capacitor Type (Insulated capacitive material is placed inside two connecting flanges that contain a seal. Air or water leaks change capacitance and impedance of the capacitive material.)	1. Oil, gas or water leaks in flanges and other types of seals	1. Better than 10^{-3} scc/s	1. Simple 2. Low cost 3. Good incipient failure detection 4. Commercially available 5. Continuous monitoring	1. Requires detector to be designed as part of the pipeline system component
(h) Nuclear Tracers [78],[79] (A minute quantity of short-life radioactive material which is soluble in the oil handled is injected into the pipeline fluid. If a leak exists, the radioactive material will escape through the leaking area of the pipe to the surrounding soil. After the pipeline is cleared with a scrapper pig and a suitable amount of non-radioactive product passed through the line, an inspection pig with a nuclear detector or an inspector travel along the line and monitor any radiation leaked into the soil.)	1. Oil leak location	1. Unknown 2. Method is claimed to accurately locate leak	1. Accurate leak location	1. Method requires complete removal of radioactive tracer from walls of pipe 2. Special personnel required
(i) Nitrous Oxide Inspection (The gas is soluble in water and oil and bubbles out of solution at low pressures. A small quantity is injected into the line. An infrared analyzed probe is used to detect leaking gas either in the soil or above the ground along the pipe.)	1. Oil leaks		1. Excellent leak location 2. Method proven and in use in pipelines	1. Large number of boreholes may be required 2. High cost
LEAKED OIL PROPAGATING INTO FLUID MEDIUM				
(j) Acoustic Sonar[64] (A sonar device directs acoustic waves along the path of a submerged pipeline. The reflected waves are detected and recorded. The location of escaping liquid is then determined from the recorded reflected acoustic waves. The reflected waves result from the difference in acoustic impedances between the escaping liquid and seawater.)	1. Oil leaks	1. Unknown	1. Simple	
(k) Acoustic Underwater[65] (Leaks from underwater oil pipelines are detected and located by a mobile receiver which moves along a path parallel to the pipeline and detects the ultrasonic frequencies in the 20 to 70 KHz range that are generated by liquid escaping from a leak.)	1. Oil leaks	1. Unknown	1. Simple 2. Low cost	

(continued)

TABLE 49 (continued)

Method[a]	Defects Measured	Sensitivity[b]	Advantages[c]	Disadvantages
(l) Laser Detection-Underwater Leaks (A laser system would be mounted on an underwater pipeline or hose string. The laser is aimed parallel to the pipe or hose to a detector mounted further away. Light transmittance would decrease with oil escaping. Thus a leak can be detected.)	1. Oil leaks	1. Depends on laser source and power, detector sensitivity and traverse 2. Minor spill sensitivity expected	1. Continuous monitoring	1. Feasibility stage for underwater 2. High cost 3. Environment that the equipment is subjected to makes practical application difficult at best 4. Detects leaks only after they occur 5. Requires highly trained personnel
ACOUSTIC ENERGY GENERATED AT LEAK SOURCE AND PROPAGATING ALONG THE LINE				
(m) Passive Ultrasonic (Portable-hand held, ultrasonic detectors that detect sounds emitted at leak source on pipeline or valve.)	1. Leaks 2. Valve damage 3. Corrosion	1. Small leaks 2. Detects medium leaks up to about 300 feet away on pipelines 3. Sensitivity depends upon size of leak, product in line, pressure in line, and soil conditions around pipe.	1. Low cost 2. Simple 3. Commercially available for above water or underwater use 4. Some incipient failure detection	1. Must be very close to leak source if it cannot be attached to leaking structure 2. Leak location only 3. Cannot be used to accurately determine severity of leak
(n) External Rods With Acoustic Sensors (Metal rods attached to pipeline at about every 1500 feet to permit the localization of leaks by monitoring acoustic energy generated at the leak and propagated to the rods.)	1. Leaks	1. Minor leaks	1. Low cost 2. Simple 3. Method is proven and used in operating lines	1. Leak located only 2. Cannot be used to determine severity of a leak
(o) Passive Acoustic Array-Leaks (Array of acoustic transducers permanently installed on pipeline to detect and locate leak from sounds emitted at the source of a leak.)	1. Oil or liquid leak detection and location	1. Depends on material, component structure, transducer spacing, etc. 2. Potentially can detect a small, slow leak (i.e., few barrels per hour) and locate the leak within a few feet 3. Sensitivity increased with application of higher test pressures or a test gas	1. Simple 2. Excellent leak detection 3. Requires little or no interpretation by personnel 4. Computerized, automated system can be adapted to existing supervisory control system	1. Medium cost 2. System in development/engineering phase 3. Reliability and performance specifications are uncertain

---

[a] Identifies Reference number.

[b] Small spill - 2,100 gal (50 barrels); minor spill 10,000 gal (238 barrels); medium spill 10,000 to 100,000; major spill - 100,000 gal.

[c] Very rough estimate of inspection costs for year for components that would typically be inspected; low cost 0 - $20K; medium cost $20K to $200K; high cost - $200K.

TABLE 50. PERIODIC PRESSURE TESTS

Method[a]	Defects Measured	Sensitivity[b]	Advantages[c]	Disadvantages
LEAKS				
(a) Pressure-Static (Monitors line integrity. When a line segment is suspected of leakage, pressure is maintained and block valves closed. Static pressure between two valves is monitored (less than an hour) for any pressure drop.)	1. Oil leaks	1. ≃ 3 PBH 2. Minor oil leaks 3. Less sensitive than hydrostatic pressure difference method	1. Low cost 2. Simple 3. Quick check of line for leaks, i.e., less than 1 hour 4. Method in use on some pipelines	1. Requires leak detection method to locate leaks 2. Variations in temperature, etc., limit sensitivity 3. Difficult to detect slow leaks 4. Out-of-service operation required 5. Cannot be used with hot or very viscous fuel oil or crude 6. Difficult in mountainous areas
(b) Hydrostatic Pressure Drop (Pipeline pressurized and pressure gages used to detect leaks by pressure drops.)	1. Fluid or gas leaks 2. Pipeline flaws, cracks, etc.	1. ≈ 0.5 BPH	1. Simple 2. Low cost 3. Provides good incipient failure detection 4. Widely used	1. Out-of-service operation 2. Potential damage to pipeline 3. Requires leak detection method to locate leaks 4. Dowtime for temperature stabilization can be of long duration 5. Use of petroleum in lines during test is risky and should be avoided 6. Cannot be used with hot or very viscous fuel oil or crude 7. Difficult in mountainous areas
(c) Pressure Difference (Pipeline pressurized. Pressure difference gages installed across a series of block valves that isolate sections of pipeline are used to detect a leak.)	1. Fluid of gas leaks 2. Pipeline flaws, cracks, etc.	1. ≈ 0.05 barrels/hour	1. Extremely sensitive method 2. Excellent incipient failure detection 3. Method is in use on some pipelines	1. Medium cost 2. Out-of-service operation 3. Use of petroleum in line during test is risky and should be avoided 4. Downtime for temperature stabilizations can be of long duration 5. Cannot be used with hot or very viscous fuel oil or crude 6. Difficult in mountainous areas
(d) Dye Tracing (Insertion of dye under pressure into pipelines, and visually look for dye leaking out.)	1. Fluid leaks	1. Minor spills	1. Simple 2. Low cost 3. Good incipient failure detection 4. Commercially available 5. Useful when residual oil or oil from external sources cause difficulty in detecting leak	1. Slow detection method 2. Requires out-of-service operation 3. Should be used only when other visual inspections cannot detect a leak 4. Use of petroleum in line during tests is risky and should be avoided

(continued)

TABLE 50 (continued)

Method[a]	Defects Measured	Sensitivity[b]	Advantages[c]	Disadvantages
(e) Seal Leak Detector Joint Type (End element tubes wrapped around a cylindrical fixture are positioned on each side of a joint and pressurized to provide a good seal. Then area in between the tubes is pressurized and this pressure is monitored with a gage. Decrease in gage pressure will indicate leak.)	1. Air or liquid leaks inside pipe	1. Very small seal leaks	1. Simple 2. Low cost 3. Commercially available 4. Good incipient failure detection 5. Reduces the need to pressurize lines	1. Out-of-service operation
(f) External Hydrostatic (Device fits over and seals small sections of piping. External pressure is applied and monitored. If an internal leak exists, pressure decrease will occur and the leak is detected.)	1. Defects in threaded or welded connections of piping 2. Pipe leaks	1. Better sensitivity than hydrostatic testing	1. Low cost 2. Simple 3. Good incipient failure detection 4. Quick test time 5. Commercially available	1. Must be applied externally 2. Not a replacement for conventional non-destructive testing such as X-ray
(g) Seal Leak Detector Thermistor Type (Portable heated thermistor device senses gas leaks through a seal that is placed over test area. Thermistor exhibits large changes in resistance with small changes in temperature caused by the leaking gas.)	1. Gas or air leaks	1. 10^{-8} scc/s for nitrogen gas	1. Simple 2. Low cost 3. Good incipient failure detection	1. Requires out-of-service operation 2. Developmental/engineering stage

(continued)

TABLE 50 (continued)

Method[a]	Defects Measured	Sensitivity[b]	Advantages[c]	Disadvantages
INTERNAL DEFECTS				
(h) Reflected Pressure Wave (Pipeline must be blocked off, emptied and filled with nitrogen and then pulsed with a pressure wave. Pressure wave reflects from cracks before it reflects from end of pipeline.)	1. Internal cracks	1. Detects large cracks of about 1 inch	1. Provides some incipient failure detection 2. Low cost	1. Out-of-service operation 2. Sensitive to internal surface roughness 3. Experimental technique
(i) Acoustic Resonance (Locates cracks in gas-filled pipelines by using the "organ pipe" resonances of the gas column in pipeline to measure distance from pipe input to crack in pipeline wall--requires microphone and sound generator at pipeline input.)	1. Cracks or gouges in pipeline wall	1. Depends upon pipeline radius and wall thickness and wavelength of sound	1. Low cost 2. Simple 3. Good incipient failure detection 4. Particularly useful in inaccessible area	1. Requires out-of-service operation
(j) Passive Acoustic Array-Acoustic Emission (Array of acoustic transducers (permanently or semi-permanently installed) installed on pipeline to detect and locate repetitive acoustic emission sounds generated at the source of the flawed material under stress.)	1. Material defects 2. External impacts 3. Valve damage	1. Depends on material, component structure, transducer spacing, etc. 2. Can detect and locate internal flaws that are growing and prior to catastrophic failure 3. Sensitivity increased with application of stresses higher than normally used	1. Excellent incipient failure detection 2. Computerized automatic system can be adopted to existing control system 3. Commercial system for periodic proof testing of tanks, pressure vessels, etc. are available 4. Continuous monitoring	1. Incipient failure data subject to interpretation as to the severity of defect but system does provide defect location for further inspections by other means 2. Medium cost 3. Reliability and performance

---

[a] Identifies Reference number.

[b] Small spill < 2,000 gal (50 barrels); minor spill 10,000 gal (238 barrels); medium spill 10,000 to 100,000; major spill > 100,000 gal.

[c] Very rough estimate of inspection costs for year for components that would typically be inspected; low cost 0 - $20K; medium cost $20K to $200K; high cost > $200K.

TABLE 51. CORROSION INSPECTION

Equipment[a]	Defects Measured	Sensitivity[b]	Advantages[c]	Disadvantages
(a) Corrosion Flow Sampling (Corrosion rate coupons, laboratory analysis of flow content, strainer and pig trap monitoring.)	1. Internal pipeline corrosion	1. Potentially can detect major corrosion 2. Corrosion trend indication	1. Some incipient failure detection 2. Widely used 3. Medium cost 4. Commercially available	1. Difficult to determine quantitatively the amount of corrosion 2. Does not locate corrosoin
(b) Corrosion metering Internal (Corrosion rate probe installed inside at the top of pipeline with an exposed element. Corrosion causes a change in electrical resistance of element.)	1. Internal pipeline corrosion	1. Potentially can detect major corrosion 2. Corrosion trend indicator	1. Some incipient failure detection 2. Widely used 3. Low cost 4. Commercially available	1. Indicates corrosion trend 2. Does not locate corrosion
(c) Corrosion metering External (Potential measurements and continuity measurements of exposed steel of pipeline.)	1. External corrosion of pipeline	1. Provides adequate measurement of conditions of cathodic protection	1. Simple 2. Low cost 3. Widely used 4. Good incipient failure detection 5. Commercially available 6. Cathodic monitoring can be done by aerial systems	
(d) Holiday Detector (Device places an electric potential between pipe section and an electrode that is in contact with outside coating of pipe. Electrode typically is a coiled spring around pipe. Electric potential is set high enough so that an arc in air is produced when thickness of coating is not satisfactory.)	1. Coating discontinuities 2. Surface defects	1. Location of pinhole or microscopic size	1. Simple 2. Some incipient failure detection 3. Commercially available 4. Low cost 5. Indicates if coating less than ideal	1. Pipe must be uncovered
(e) Visual Corrosion Inspection	1. External corrosion of pipeline	1. Poor	1. Low cost 2. Simple 3. Some incipient failure detection	1. Subject to personnel error 2. Not quantitative
(f) See also nondestructive equipment for corrosion measurement in Table 3-11.				
(g) See also inspection pigs for corrosion measurement in Table 3-12.				

[a] Identifies Reference number.

[b] Small spill < 2,000 gal (50 barrels); minor spill 10,000 gal (238 barrels); medium spill 10,000 to 100,000; major spill > 100,000 gal.

[c] Very rough estimate of inspection costs for year for components that would typically be inspected; low cost [illegible] < $20K; medium cost $20K to $200K; high cost > $200K.

TABLE 52. STANDARD NONDESTRUCTIVE INSPECTION

	Equipment[a]	Defects Measured	Sensitivity[b]	Advantages[c]	Disadvantages
(a)	Active Ultrasonics (Detector sends ultrasonics wave pulses through or along pipeline and then detects distorted wave pulses or reflection times of returned waves from defect areas.)	1. Internal defects 2. Thickness measurements 3. Corrosion measurements	1. About 1% thickness variations can be detected easily 2. Internal defects such as 10 mm x 1 mm x .3 mm can be detected at distances up to 2 meters away	1. Low cost 2. Widely used inspection method 3. Excellent incipient failure detection 4. Can be used for most materials 5. Commercially available	1. Difficulty in providing a test report of internal defects because of interpretation difficulty
(b)	X-Ray (Radiographic method uses X-ray source to penetrate through a material. Intensity of penetration is modified by passage through material and defects. Visible contrast on film shows defect free areas and defect.)	1. Internal defects 2. Thickness measurements 3. Corrosion	1. Excellent sensitivity about 1% of thickness variations can be detected 2. Poor resolution of thin horizontal cracks 3. Gives average wall thickness for through pipe inspection	1. Can be used for almost any material 2. X-ray records easy to interpret 3. High reliability 4. Commercially available 5. Excellent incipient failure detection	1. High cost 2. Radiation safety measures required 3. Cumbersome equipment
(c)	Radio Isotopes Gamma Ray (Same type of operation as (c) but a radioactive source is used instead of X-ray source. Source and detector film at 180°, for on land inspections. Source and detector can also be on same side for back scatter method.)	1. Internal defects 2. Thickness measurements 3. Corrosion	1. Less sensitive than X-ray 2. Defects about 2 mm length and 1 mm depth can be detected underwater 3. Gives average wall thickness for through pipe inspections 4. Provides severity of flaw	1. Can be used for any materials 2. Widely used 3. Records easy to interpret 4. Highly reliable 5. Excellent incipient failure detection particularly for underwater use 6. Commercially available	1. High cost 2. Radiation safety measures required 3. Slow inspection
d)	Magnetic Particle (Magnetize inspected component apply and magnetic particles to magnetized area. If flaw close to surface, magnetic particles will deposit themselves along flaw because of leakage in magnetic flux at the discontinuities.)	1. Essentially all defects at or near surface	1. Highly sensitive for surface or subsurface flaws 2. Defects about 1 mm in length can be detected 3. More sensitive than penetrant	1. Simple 2. Can be used underwater 3. Low cost 4. High reliability 5. Excellent incipient failure detection 6. Commercially available	1. Can only be used on ferromagnetic materials 2. Sudden changes in permeability produce false defect 3. Demagnetization is usually required
(e)	Ultrasonic Imaging (Holographic) (Similar to other kinds of holography but uses an array of transducers for high frequency coherent sounds in order to penetrate inside structure for 3-dimensional acoustic image view of interior of soild. Device includes scanning head and ultrasonic holography computer signal processor to recreate image.)	1. Defects inside the material in 3 dimensions 2. Corrosion/erosion 3. Pits, cracks, etc. 4. Loss of material on inside or outside of pipe weld	1. Flow areas of about 0.2 mm x 0.2 mm 2. Instrument can be set up to meet any API specification 3. Thickness resolution of about 0.05 mm 4. Provides length, width, shape and depth of crack 5. Penetrates to about 1 meter in solid steel	1. Good hard copy picture of internal flaw with little or no interpretation of data required 2. Has been used underwater with good success 3. Device can be hand held or attached to pipeline 4. Excellent incipient failure detection 5. Commercially available in 1978	1. Medium cost 2. Device has been used successfully for a number of underwater applications and needs engineering design for specific application 3. Reliability and performance specification are uncertain at this time

(continued)

TABLE 52 (continued)

Equipment[a]	Defects Measured	Sensitivity[b]	Advantages[c]	Disadvantages
(f) Eddy Current (A detector coil carrying alternating current is brought near a material specimen and eddy currents are induced by electromagnetic induction. Discontinuities in material change the magnitude of induced eddy current.)	1. Internal defects 2. Cracks 3. Thickness 4. Voids 5. Corrosion	1. Cracks 0.2 to 0.4 mm sensitivity	1. Locating defects near surface 2. Low cost 3. Simple 4. Commercially available 5. Good incipient failure detection 6. Works well on thin materials	1. Does not work in nonmetals
(g) Penetrants (A liquid penetrant is applied to the inspected surface. After sufficient penetrating time, the excess penetrant is wiped off and a white powder is typically applied to the surface. After a period of time penetrant seeps out of crack and reduces the whiteness of the powder and the defect can be observed.)	1. Surface cracks, laps 2. Internal defects with surface openings	1. Cracks, defects, etc. of about 1 mm width 2. Much more sensitivity than visual inspection	1. Simple 2. Covers a large area 3. Low cost 4. Commercially available 5. Good incipient failure detection	1. Will not work with surfaces covered with oil, grease, paint, etc.

[a] Identifies Reference number.

[b] Small spill < 2,000 gal (50 barrels); minor spill 10,000 gal (238 barrels); medium spill 10,000 to 100,000; major spill > 100,000 gal.

[c] Very rough estimate of inspection costs for year for components that would typically be inspected; low cost 0 - $20K; medium cost $20K to $200K; high cost > $200K.

TABLE 53. PIPELINE INSPECTION PIGS

Equipment[a]	Defects Measured	Sensitivity[b]	Advantages[c]	Disadvantages
PROPELLED THROUGH PIPELINE BY FLUID FLOW				
(a) Magnetic Flux (Electromagnetic) (Changes in wall thickness affects magnetic field. Induced magnetic field and detection accomplished with electromagnets or permanent magnets.)	1. Corrosion 2. Hardspots, mfd. flaws 3. Girth welds, pits 4. Cathodic protection 5. Improper bends of pipeline 6. Gouges 7. Wrinkle brads 8. Hydrogen blisters 9. Bends	1. Severity of corrosion in three ranges - 15-30% of wall 30-50% of wall >50% of wall 2. Approximately 1/8 inch defect 3. Severity of pitting	1. High reliability 2. Locates defects 3. Permanent record 4. Monitors integrity of line 5. Locates potential failures before they become catastophic 6. Help evaluate effectiveness of cathodic protection coating 7. Commercially available for 6-36 inch diameter lines	1. High cost 2. Difficult to interpret magnetic anomalies 3. Requires human interpretation 4. Electromagnetic type cannot determine if defect is inside or outside of pipe 5. Permanent magnet type can get stuck in pipeline and difficult to remove 6. Anomalies around girth weld difficult to detect 7. Does not detect thin cracks very well
(b) Kaliper (Finger mechanism in pig transmits changes in pipe diameters to a charting device in pig housing.)	1. Measures changes in inside pipeline diameter 2. Detects dents, buckles 3. Detects obstructions 4. Changes in wall thickness 5. Flat spots, bends 6. Partially closed valves	1. Abrupt changes in wall thickness of 1/8" or more 2. High degree of accuracy of measuring length of heavy wall pipe	1. Extremely useful in new pipeline construction 2. Medium cost 3. Locates size and location of significant changes in pipeline	1. Much lower sensitivity than magnetic flux inspection pig
(c) Active ultrasonics (Ultrasonically scans pipeline in transverse direction using active ultrasonic scanning tool.)	1. Pipe wall thickness 2. Laminations 3. Inclusions 4. Cracks	1. Indicates dimension of defect	1. Location of defect 2. Permanent record 3. New units are currently under development for pipelines that are of med. cost & require min. interpretations.	1. High cost 2. Difficult to interpret 3. Requires human interpretation 4. Not widely used
(d) Passive Ultrasonics (An escaping fluid from a pipeline leak emits sounds. A passive ultrasonic detector, mounted in an oil tight container, detects the leak.)	1. Detection of fluid escaping through hairline cracks or small corrosion holes.	1. 3 to 5 gallons per hour leaks	1. Locates leak within a few feet 2. Should work well if a leak detector pig is built and dedicated for a specific pipeline	1. High cost 2. Not commercially in use in the U.S. because of difficulty in applying device to a variety of pipelines 3. Requires some development for reliable results 4. Background noise currently limits leak resolution
(e) TV Camera (TV inspection camera with low light TV camera and video tape or TV monitor.)	1. Visually inspects inside of pipeline for cracks, pits, etc.	1. Slightly better than visual inspection 2. 360° viewing	1. Simple 2. Permanent record 3. Medium cost	1. In feasibility stage only because TV signals currently cannot be transmitted without a cable attached to camera.
(f) Nuclear (Nuclear source installed in inspection pig. Minute radioactive quantities transmitted through a leak is sensed by external detectors.)	1. Small hole through cracks	1. Sensitivity uncertain	1. Simple	1. Feasibility stage only 2. Radiation safety requirement 3. High signal attenuation from source caused by water 4. High cost
(g) Ultrasonic Holographic Imaging (3-dimensional view of inside of pipeline wall-includes scanning head, recording module, electronic holographic computer signal processor and power supply.)	1. Detects inside the material 2. Corrosion and or erosion 3. Pits 4. Loss of material on inside or outside of wall 5. Wall thickness	1. Flaw area of about 0.01 in x 0.01 in 2. Instrument can be set to meet any API specification 3. Thickness resolution of about 0.02 in 4. Provides 3 dimensional image showing length, width, geometry and depth	1. Excellent picture of inside pipe 2. Covers 5 to 10 miles per hour 3. Excellent incipient failure detection 4. Simple interpretation of data	1. High cost[d] 2. Product not commercially available 3. Requires high developmental cost 4. Reliability and performance specifications are uncertain

[d] Development costs of this type of inspection pig to be propelled through the water fluid flow may range from 2 to 5 million dollars for a highly reliable version.

(continued)

TABLE 53 (continued)

Equipment[a]	Defects Measured	Sensitivity[b]	Advantages[c]	Disadvantages
(h) Electromagnetic Noncontact Transducer EMAT (Electromagnetic noncontact transducers in inspection pig focus a beam of energy directed around the pipe circumference. A longitudinal stress corrosion crack or region of corrosion reflects energy back to a detector transducer. Device is blown through pipe by a gas stream.)	1. Longitudinal stress corrosion cracks 2. Generalized pipe wall thinning	1. Unknown	1. Well suited when there is difficulty coupling sound to pipeline through a liquid or grease 2. May work well at high speeds--20 mph	1. Experimental/feasibility stage
(i) Super Atmospheric'' (A fluid is flowed through a pipeline at superatmospheric pressure. A floatable leak sensor, which is responsive to pressure and velocity differentials caused by a leak, is moved through the pipeline along with a fluid. Sensor stops movement through conduit at location of a leak.	1. Leaks	1. Unknown	1. Potentially more sensitive than acoustic inspection pig	1. Require out-of-service operations 2. Requires elevated pressures
(j) Flow Meter'' (Unit comprises a steel cylindrical pig sliding inside pipe on flexible drawing bonds. Inside is a flow meter and electronics package. When leak is detected by a drop in test pressure unit is introduced into line and positioned by pumping. At point of leakage a sharp change in flow rate and direction occurs and is detected by flowmeter.)	1. Leaks	1. Accurate leak location	1. Single 2. Particularly useful for undersea lines	1. Leak location only 2. Out-of-service inspection
INSPECTION PIGS PUSHED OR PULLED THROUGH PIPELINE OR HOSE STRING VIA CABLES, ETC.				
(k) Camera (Low-light type camera and video tape or TV monitor.)	1. Visually inspect inside of pipeline for cracks, corrosion pits, paint condition, etc.	1. Slightly better than visual sensitivity 2. 360° viewing	1. Medium cost 2. Can be used to inspect inside of hoses particularly in evacuated condition 3. Some incipient failure detection 4. High reliability 5. Commercially available 6. Can be stopped for viewing of questionable areas of pipe or hose.	1. Requires out-of-service operation 2. Currently limited from 1000 to 3000 ft. 3. Requires winch to pull camera 4. Requires clean, clear water 5. Works best with fresh water
(l) Stereo Pairs Camera (Strobed light exposures with no camera shutters.)	1. Same as above	1. Slightly more sensitive and better pictures than camera	1. Medium cost 2. Can be used to inspect inside of pipeline or hoses 3. Some incipient failure detection 4. High reliability 5. Commercially available	1. Requires a conductive coaxial cable 2. Currently limited to about 3000 ft. 3. Requires clean, clear water

(continued)

TABLE 53 (continued)

Equipment[a]	Defects Measured	Sensitivity[b]	Advantages[c]	Disadvantages
(m) Eddy Current (Eddy current changes in non-magnetic tubing caused by defects are detected by a recording impedance bridge.)	1. Wall thickness 2. Pits 3. Cracks 4. Holes 5. Corrosion 6. Surface or near surface defects	1. Longitudinal cracks .004 in deep by .4 in in length can be detected 2. Changes in wall thickness of 1% in a 0.4 in length can be detected	1. Medium cost 2. Good incipient failure detection 3. Widely used 4. Commercially available 5. Locates defects near surface	1. Insensitive to circumferential cracks, short cracks and shallow cracks 2. Requires out-of-service operation 3. Non-magnetic materials only 4. Limited to a few 30 foot lengths of pipe
INSPECTION PIGS WITH MANNED INSPECTORS (PUSHED OR INTERNALLY POWERED THROUGH LARGE PIPE LINES)				
(n) Inspection methods Available (See Table	1. All internal defects and pipeline corrosion	1. Best overall sensitivity of any inspect method for pipeline	1. Best overall incipient inspection technique for internal examination of pipeline 2. Operational under limited use	1. Very high cost 2. Slow 3. Requires out-of-service operation 4. Feasibility stage for powered type vehicle
(O) Ultrasonic (Holographic Imaging) (See discussion (g) Method was applied to ALYESKA pipeline using manned inspectors and a powered vehicle.)	1. Some as (g)	1. Same as (g)	1. Excellent hard copy pictures of internal flaw in pipeline 2. Excellent incipient failure detection 3. Simple data interpretations 4. Commercially available	1. High cost 2. Device must be designed and engineered for specific pipeline 3. Reliability and specifications are uncertain at this time 4. Requires out-of-service operation
(p) Ultrasonic Riser[74, 75] Unit removed inside riser while the ultrasonic transducer rotates to obta in helican scan.	1. Riser thinning, cracks, etc.	1. Better then 20% of thickness	1. Small enough to pass around pipe elbows without jamming. 2. Lightweight 3. Commercially available.	1. Not self-propelled. 2. Out-of-service inspection.
INSPECTION PIG TRACKING				
(q) Tracking (Inspection pigs are located in pipeline by monitoring signal from nuclear, acoustic pinger or nuclear source inside inspection pig. Also cleaning pigs or an acoustic pinger inside a polyurethane sphere are often used.)	1. Locates stuck inspection or cleaning pig caused by pipeline defects--improper bending or medium or major leaks	1. Sensitive only to large defects in pipeline	1. Simple locating methods 2. Low cost for polyurethane spheres 3. Commercially available	1. Insensitive to most pipeline defects

---

[a] Identifies Reference number.

[b] Small spill < 2,000 gal (50 barrels); minor spill 10,000 gal (238 barrels); medium spill 10,000 to 100,000; major spill > 100,000 gal.

[c] Very rough estimate of inspection costs for year for components that would typically be inspected; low cost 0 - $20K; medium cost $20K to $200K; high cost > $200K.

TABLE 54. SURVEY-PIPELINE SYSTEM CHARTING AND DEPTH OF BURIAL

Equipment[a]	Defects Measured	Sensitivity[b]	Advantages[c]	Disadvantages
ON LAND				
(a) Radar[d,e] (Radar impulse passes through earth to pipe. A change in conductivity, permittivity or permeability causes impulse to be reflected to detector.)	1. Precise underground pipeline location	1. 90 percent accuracy in wide range of soils 2. Location accuracy within 6 inches	1. Locates both plastic and metal pipe 2. Low cost	1. Requires some operator training
UNDERWATER				
(b) Sonar-Sidescan (Inspects for topographical features and bare spots in pipelines. An acoustical transducer in a towed fish (travelling close to the sea bottom) sends a pulsed and almost horizontal beam. The strength of the echo of the transmitted beam provides sufficient information to determine size and orientation of pipeline bare spots.)	1. Bare spots in the undersea pipeline 2. Pipeline orientation	1. Exposed undersea pipeline surfaces as small as 1 inch	1. Some incipient failure detection 2. Fast inspection 3. Covers wide area 4. Low cost 5. Commercial systems or services available 6. Method can be used simultaneously with sub-bottom profiling inspection to obtain depth of pipeline burial	1. Requires skilled interpretation of data
(c) Sonar-Penetrating Sub-Bottom Profiling (Two acoustical transducers, one penetrating through overburden of pipeline and one that reflects from pipeline overburden, are towed in a tow fish. Transducers send pulsed vertical beams. The strength of reflected echos provide sufficient data to determine depth of burial.)	1. Depth of burial 2. Trench delineation 3. Pipeline locations and orientation	1. Depth of burial to 2 inches	1. Provides incipient failure detection 2. Fast inspection 3. Covers wide area 4. Low cost 5. Commercial systems or services available	1. Requires skilled interpretation of data
(d) Acoustic Holography[f] (Phased acoustic transducers traverse 10 ft above seabed. Ultrasonic signals received by array are transmitted to the surface and displayed real-time where operators examine an isometric contour view of the sea bottom and pipe).	1. Pipe location 2. Dents 3. Damage from anchors 4. Misalignment 5. Concrete defects	1. Locate 3 ft diameter pipelines buried 30 ft below mudline in 10,000 ft water depths.	1. Tested successfully	1. Not demonstrated on full-scale. 2. High cost.

(continued)

TABLE 54 (continued)

Equipment[a]	Defects Measured	Sensitivity[b]	Advantages[c]	Disadvantages
SURVEYING-COMPONENT LOCATION				
(e) Diver Using Microwave Position System (Diver walks the pipeline and will hold a taunt buoy line. A microwave positioning system antenna is mounted over the buoy and is used to accurately locate the position of a diver.)	1. Precise pipeline location 2. Pipeline damage	1. Precise pipeline location to 600 feet of water depth	1. Covers up to about 1/2 mile per day 2. Can be used in turbid water 3. Provides visual inspection by diver 4. Particulary useful for new pipelines 5. Excellent incipient failure detection 6. Inspection services available	1. High cost 2. Currently limited to about 60 feet of water depth
(f) Diver Using Acoustic Transponder System (Diver walks pipeline and transmits position with an acoustic transponder with a 1° beam.)	1. Precise pipeline location 2. Pipeline damage	1. Precise pipeline location to 600 feet of water depth	1. Same as for (d) except item 6 2. Diver can leave a locating transponder at an area where pipe needs repair. This allows easy location for later repairs	1. High cost 2. Development stage
SCOUR				
(g) Diver Visual Inspection	1. Identifies unprotected areas caused by scouring that can result in excessive corrosion	1. Visual	1. Simple 2. Low cost 3. Some incipient failure detection	1. Visual only and subject to interpretation 2. Cannot find scour areas that may be covered up by current after storm
(h) Diver Inspections With Pneumofathometer Device (Diver uses hand held hose to probe bottom surface around the component. Air is inserted into the hose from diver supply ship. A gage on the supply ship is used to measure pressure of the hose line in feet of sea water to determine bottom surface depth.)	1. Identifies unprotected areas caused by scouring 2. Corrosion 3. Bottom topography	1. Visual 2. Accurate bottom topography measurement	1. Simple 2. Low cost 3. Some incipient failure detection	1. Visual only and subject to interpretation 2. Cannot find scour areas that may weaken structure but may be covered up after storm
(i) Continuous Monitoring (Electrode resistance Depth Measuring** Magnetic Beacon** Electromagnetic Beacon**.)	1. Continuous scour monitoring	1. Scour resolution to within a foot	1. Detect scour areas that may weaken structure but may be covered up by storm 2. Continuous monitoring 3. Especially useful in deep water where diver or submersible vehicle inspections are costly 4. Good incipient failure detection	1. Medium cost 2. Not particularly advantageous at short depths (i.e., 150 feet) from a cost consideration 3. Systems require development and engineering design

[a] Identifies Reference number.

[b] Small spill < 2,000 gal (50 barrels); minor spill 10,000 gal (238 barrels); medium spill 10,000 to 100,000; major spill > 100,000 gal.

[c] Very rough estimate of inspection costs for year for components that would typically be inspected; low cost 0 - $20K; medium cost $20K to $200K; high cost > $200K.

TABLE 55. MISCELLANEOUS

Equipment[a]	Defects Measured	Sensitivity[b]	Advantages[c]	Disadvantages
(a) Passive Acoustic Array Outside Forces (Array of acoustic transducers installed on or near pipeline to detect and locate acoustic sounds generated at the source of outside damage from equipment impacts, digging, etc.)	1. Outside forces	1. Detects and locates serious third party damage using widely separated sensors	1. Excellent incipient failure detection 2. Computerized automatic system can be adopted to existing control systems 3. Can be used underwater 4. Permanent records 5. Can be used at all times	1. Incipient failure data subject to interpretation as to the severity of defect but system does provide defect location for further inspections by either means 2. Medium cost
(b) Passive Acoustic Machinery Damage[75] (Acoustic transducers hand held or permanently installed on machinery detect abnormal sounds emitted when internal defects start to occur in machinery. Strain transducers or accelerometers can also be used for this detection. System usually provides continuous monitoring and alarms.)	1. Internal defects in machinery 2. Bearing damage 3. Valve damage		1. Commercial system available 2. Good incipient failure detection 3. Reduces machinery maintenance cost 4. Permanent records 5. Continuous monitoring	1. Data subject to interpretation as to the severity of internal defect but systems typically give adequate warning before a failure can occur
(c) Liquid Level Sensor (Detects level of liquid in tanks, piping, etc. using any one of many available methods-ultrasonic, optical, microwave, nuclear, etc.)	1. Oil levels 2. Oil leaks into containers	1. Better than 1%	1. Simple 2. Low cost 3. Some incipient failure detection 4. Commercially available 5. Continuous monitoring	
(d) Laser Holography Interferometry (Surface is inspected with a laser. High resolution film is exposed by laser light reflected from surface. Developed film produces a 3-dimensional hologram. If surface undergoes a topographical change, another exposure is made on the same film and minute changes in topography can be recorded. Changes can be detected by fringe patterns shown in holographic reconstruction.)	1. Small topographical changes	1. Wavelength of laser light	1. Commercially available 2. Some incipient failure detection for hoses	1. Medium to high cost 2. Requires trained personnel 3. Very difficult to implement 4. Very limited inspection use

(continued)

TABLE 55 (continued)

Equipment[a]	Defects Measured	Sensitivity[b]	Advantages[c]	Disadvantages
(e) Magnetic Chip (Installed on machinery and periodically examined.)	1. Internal defects in machinery 2. Bearing damage		1. Simple 2. Low cost 3. Commercially available 4. Some incipient failure detection 5. Reduces machinery maintenance costs 6. Continuous monitoring possible	
(f) Oil Odor (Inspector detects oil from smell.)	1. Oil leaks	1. Small leaks	1. Simple 2. Can be used in darkness or in bad weather 3. Particularly useful in darkness at sea	1. Subject to personnel error 2. Winds may cause oil odor not to be detected 3. Not quantitative
OTHER METHODS				
(g) Integrated Machinery Inspection[77]				
(h) Control Room Monitoring, Alarm Shut-off				
(i) Thermal or Infrared				
(j) Thermal Paint				
(k) Microwave				
(l) Filtered Particle				
(m) Sonic				

---

[a] Identifies Reference number.

[b] Small spill < 2,000 gal (50 barrels); minor spill 10,000 gal (238 barrels); medium spill 10,000 to 100,000; major spill > 100,000 gal.

[c] Very rough estimate of inspection costs for year for components that would typically be inspected; low cost 0 - $20K; medium cost $20K to $200K; high cost > $200K.

Because most pipelines are buried, oil escaping in either small or large quantities may not be observed, or, if observed, only small quantities or traces may be visible. Also, in some types of soil, the oil may take a particularly long time to surface. These migration effects[52,54,55,56] occur because the soil between the line and surface absorbs and spreads oil below the surface. Often this causes the distance between the discovered leak and the actual leak location to be quite large. When pipelines are installed in gravel bottoms or sandy bottoms, this can become a particular problem.

Underwater lines have other significant problems with visual inspections. If a leak occurs underwater, the oil can be spread by currents. Many leaks cannot be detected by visual observation. For example, a small crack in the pipeline may allow seawater to seep inside undersea pipelines which are located at depths at which external pressures are greater than internal pressures. This water can cause excessive internal corrosion. In the extreme case, a crack can grow undetected to a critical size, then rupture and cause a major pollution incident.

These and other factors make it difficult to detect and locate a pipeline leak. Furthermore, numerous instances of careless losses from small quantities of oil, such as from dumping crackcase oil, losses from domestic fuel oil tanks, or spills from ships present difficulties in discriminating between a pipeline leak and other oil spillage.

Methods that aid visual inspection are quite useful in improving the ability of an inspector to detect and locate a leak. Aided inspections might be an inspector walking the line with a hydrocarbon detector, an inspection plane eqippped with remote oil spill detectors or an inspector on the deck of a ship or at a marine terminal viewing the water with an ultraviolet light source or low-light TV monitor. Use of a hydrocarbon detector while walking the lines in populated or hazardous areas appears particularly advantageous for detecting small leaks, such as could occur from corrosion. These small-volume corrosion leaks may take either a long time to surface or may only surface trace amounts. Inspection with a hydrocarbon detector may provide detection of a leak before it can cause any surface damage and possibly before it can cause damage to underground water supplies.

5.3.2.2 Oil Spill Detectors On or Near the Water--

Oil spill detectors such as those in Table 47 might be used to supplement visual inspection. These detectors are of low to medium cost and do not interfere with pipeline operations. A few advantages of these devices are that they are not subject to personnel error and most provide continuous detection. Many oil companies are currently using oil spill detectors (Table 47(c)) at supertanker terminals and at other marine terminals. However, most of these oil spill detectors are still under development or evaluation and are not in common use.

Two oil spill detectors appear to have a particularly good potential of effectively minimizing oil pollution. One is the platform infrared type (Table 47(c)) for use at marine terminals. This may be particularly beneficial when a considerably amount of petroleum is transported. The other is the bistatic, active, infrared type (Table 47(j)) for channels and rivers.

5.3.2.3 Internal Fluid Variations During Oil Transfer--

Unusual fluid variations in a pipeline during transport can indicate possible pipeline system leaks. A variety of methods that detect fluid variations are available for leak detection and inspection of the pipeline system during normal operations when oil is transported. These are given in Table 48 and include:

- Pressure deviation
- Volume comparison (differentials)
- Flow rate comparison (differentials)
- Flow rate deviations
- Over-and-short accounting (long-term)
- Mathematical modeling
- BS&W deviations
- Pressure difference with reference and threshold
- Fluid mass deviations
- Negative surge
- Inspection pig-passive ultrasonic
- Pressure fluctuations
- Production surveillance monitor-pressure fluctuations.

These methods normally cause only minimal interference with line operations and most are of low to medium cost. All methods provide continuous surveillance of the line except the passive ultrasonic pig and long-term over-and-short. Most methods primarily detect major leaks or catastrophic failures. They are used to trigger controls to quickly shut the system down and thus minimize the volume of spillage. None of these methods, except possibly mathematical modeling, can reliably detect small leaks (a few barrels per hour) over a short period of time (hours). A few methods, however, are capable of detecting small leak rates over long time periods.

The first five methods are commonly used for pipeline leak detection by the U.S. oil industry. In general, modern supervisory control systems are computer controlled and many provide continuous monitoring of pressure deviation, volume comparison, flow rate comparison and flow rate deviations. Hardwired meter flow comparators are often installed in areas where the risk of pollution is high. They are particularly effective where more of these leak detection methods might be implemented. A leak detection system, for example, might continuously monitor pressure drop and compare flow rates and flow deviations between two points. If one or more measurements exceed preset values, an alarm would be sounded and appropriate valves and equipment would automatically be operated to shut down the system. Normally, an excessive pressure drop combined with a flow rate increase are strong indicators of a leak.

Varying operating conditions, fluids, transients, temperatures, line pack and other factors cause changes in these pipeline system measurements that often result in false indications of leakage and cause false alarms and shudowns. In order to account for varying conditions and minimize false alarms, three things are normally done. First, a variety of highly accurate metering equipment (i.e., pressure transducers, flow meters, temperature gauges, etc.) are installed. Then sophisticated computer programming with various scanning rates, error bands, checking schemes and displays are used in the monitoring systems. Finally, the system sensitivity is decreased and setpoints raised to minimize false alarms. For most lines, this results in decreases in sensitivity that precludes detection of small or minor spills.

Short-term losses (one hour or less) of from 1 to 5 percent of throughput are normally detectable with these types of continuous monitoring systems. For a throughput of 10,000 bblh, this corresponds to a leakage rate detection of 100 to 500 bblh. Long-term (24 hours or more) detection of losses ranging from 0.2 to 1 percent of throughput might be expected; this corresponds to leakage rate detection of 20 to 50 bblh. Supplementary methods such as mathematical computerized modeling, which accounts for many varying operating conditions and fluid changes, might be adapted to an existing supervisory control system to provide more sensitive (up to a factor of 10) leak detection. If implemented, small and minor spills might be detected. Mathematical modeling is currently being developed and evaluated by a number of companies. The method has been implemented on a few crude lines.

Long-term over-and-short accounting is the most common means of providing an indication of a leak. It requires only conventional metering, i.e., LACT and tank gauging, and standard accounting of receipt and delivery tickets and inventory of the lines and tanks. This existence of leakage is normally suspected when a shortage exceeds about 0.1 percent of long-term (weekly, monthly or yearly) throughput.

On large lines, gross barrels in and out, then net barrels in and out, are looked at on the basis of total volume. The only difference between net and gross is in the BS&W. A loss/gain is run on water as is done with oil because BS&W is a mirror image, i.e., BS&W gain is an oil loss or vice versa. BS&W can provide both leak detection and a check or gross volume to identify volumetric errors. This leak detection method is particularly useful in underwater lines where external pressures are higher than internal pressures and seepage of water can occur into the line through a crack. The measurement is quite inaccurate (see Section 4.3.2.3), and only large leaks are capable of detection.

Pressure difference with reference and threshold is a recently patented method. At this time there is insufficient information for proper evaluation.

Detection of leaks by monitoring the deviation in mass at the line input and output is attractive because pressure and temperature changes do not affect the measurement. The method requires that density be measured directly. Fluid mass measurement is currently carried out on mixtures of light products, i.e., natural gas mixtures. In this application, the coefficient of expansion of light products is not known, and this is the only method that has been used to successfully measure these fluids.

Negative surge leak detection is used on a few pipelines. Leak detection accuracies (about 600 bblh) are not as good as other methods. However, the method is quite simple and it can provide an inexpensive check or backup system for large leaks.

The ultrasonic inspection pig is propelled through the line by the fluid flow. It detects a leak by sensing the acoustic energy generated at the pipeline leak source. This energy is propagated via acoustic waves from the pipe inner wall through the fluid to ultrasonic detectors installed in the pig. Leak location is determined from tape recordings of both the time the leak is detected and distance the device travels. The method is currently used in a few lines. Leak detection capabilities of a few barrels per hour are claimed. Because of the high cost for a single inspection of the line, it is used at infrequent intervals ranging from six months to five years. This type of inspection pig has a number of limitations. It is particularly difficult to apply the same unit on a variety of lines because the leak detection sensitivity varies with the type of line, and leak detection background noise often presents false indications of leakage.

Experimental work currently is being carried out on the pressure fluctuation method. The basic concept is to detect the fluctuations with an array of pressure or acoustic sensors inserted in the line. The fluid turbulence generated by a leak is propagated in the fluid along the line and sensed by the detectors. The method is attractive because of its simplicity and the wide transducer spacing. The method is also attractive for detecting and locating the wave fluctuations in the line that are generated by impacts from outside forces.

The production surveillance monitor measures flow rates in the typical two-phase flow in production lines. The monitor has been proven in field tests and has been implemented on a number of lines. When used in a continuous monitoring system, it can provide indications of anomalous changes or well problems such as pipe leaks or pump malfunctions.

5.3.2.4 Detecting and Locating Leaked Oil On or a Short Distance from the Pipeline--

Methods for detecting and locating leaked oil using sensors located on or at a short distance from a pipeline are given in Table 49. These methods differ from those in the previous two sections because oil need not travel to the surface of the soil or water for detection and the methods potentially provide accurate leak location. A number of these methods are new or are in the feasibility or development stage.

The most promising of these types of continuous monitoring leak detection methods are:

- Passive acoustic array
- Shroud with electromagnetic pulsed coaxial cable
- Continuous thermistor
- Tape detection.

The passive acoustic array (see also Section 5.3.2.3) potentially is capable of detecting and locating the following: (a) leaks to a few barrels per hour; (b) internal pipeline defects that may result in leaks; and (c) (most importantly) outside damage and pipeline ruptures. The other three methods are capable of detecting leaks ranging from a few barrels per hour to pipeline rupture. However, these three methods are not considered to be as effective as the acoustic array and are expected to be more expensive. The double walled pipe is too costly to be considered except on short sections of the line in sensitive areas. The oil-soluble tubing method has been a failure on at least one pipeline. All of these continuous monitoring methods would require retrofitting the line, except possibly the passive acoustic array when used for outside damage detection only (see Section 5.3.2.3).

Other methods in Table 49 can also be applied to the entire line but are normally used on a periodic basis for: checking the integrity of the line, locating leaks, or locating and verifying a suspected leak. The nuclear tracer method appears to be most effective, but very costly, for periodic checking of the line and locating leaks. It has been implemented on a few lines, and high leak location accuracy is claimed. The hydrocarbon probe is considered to be quite effective in detecting and locating small leaks in undersea or underwater lines. Rods installed permanently on the pipeline and used in conjunction with acoustic sensors are used by a few pipeline companies to locate and verify a suspected leak. Nitrous oxide injection is costly but has been shown to provide very accurate leak location. These methods normally cause only limited interference with the line.

The remaining methods in Table 49 are limited to checking for suspected leaks of only sample areas of the pipeline. Some would require excessive costs for inspecting a complete line, while others are not considered practical for the entire line. Although useful in locating known or suspected leaks, these methods are limited and not considered as practical means of significantly reducing petroleum leakage.

5.3.2.5 Periodic Pressure Tests--

The periodic pressure tests given in Table 50 provide checks of the pipeline for leaks and/or checks for internal defects that may result in a leak. These methods require either limited interference with pipeline operations and/or retrofitting. Pressure tests primarily for detecting leaks are:

- Pressure static
- Hydrostatic
- Pressure difference
- Dye tracing
- Seal leak detector-joint type
- External hydrostatic
- Seal leak detector-thermistor type.

Pressure static, hydrostatic and pressure difference are the only methods that may be capable of effectively testing the complete line for leaks. However, these methods require that the lines be shut down and they do not locate the leaks. They are generally considered as pressure-volume-temperature-time (PVTT) test methods. Although less sensitive, the pressure static method can be carried out in a relatively short period of time. The other two methods require that the line reach temperature stabilization, which may take as much as three days. Also pressure static does not have the oil spill risk[a] problem that exists when petroleum is left in the line, as is often done, for the other two methods. Simple hydrostatic proof testing is widely used in the petroleum industry to both test new lines and to check existing lines. For typical lines, the test is carried out every two to five years. Leak sensitivity is about 0.5 BBLH; this is about 10 to 100 times more sensitive than the methods discussed previously. The pressure difference method has a demonstrated leak sensitivity of about 0.05 BBLH on foreign lines. Despite its superior leak sensitivity, the high cost of the method has generally precluded its use in the U.S.

Even better leak sensitivities are expected if the PVTT leak detection systems are supplemented by mathematical modeling of the line. Should a leak be detected, methods such as described in Section 5.2.1.3 could be used for leak location. Additionally, insertion of dyes during these tests can be advantageous in providing leak location, particularly when residuals from previous spills cause difficulty in detection. The remaining three methods can be implemented advantageously in certain limited applications.

---

[a] Methods requiring elevated pressures present a serious spill risk problem when the line is filled with petroleum. If a line should fail under pressure the petroleum would present a serious hazard particularly in high risk locations such as urban areas or near water.

Pressure test methods for detecting and locating internal defects include:

- Reflected pressure wave
- Acoustic resonance
- Passive acoustic array - acoustic emission.

The capability of checking lines for internal defects has been demonstrated on petroleum pipelines for the pressure wave and acoustic resonance methods. Both methods require that the pipeline be emptied and filled with a gas. The acoustic resonance technique appears best suited for testing inaccessible areas of a pipeline. These methods typically cause only limited interference with the line. A permanently installed passive acoustic array is in the development stage, but has been shown to be effective for detecting leaks and incipient failure during experimental tests on actual lines. Internal defects, however, can only be detected when the line is pressurized. The method typically requires close sensor spacing and is considered a retrofit. However, in high-risk areas, the method might be considered despite high retrofitting costs.

5.3.2.6 Corrosion Inspection--

External pipeline corrosion is the major cause of spills from older pipelines (those installed before 1950). Since the 1940's, improved techniques, such as pipeline coatings and cathodic protection systems, have reduced the number of oil spill incidents from new lines to a level about equal to internal corrosion. This can be seen in Table 25, which identifies causes of spills in the United States. In contrast, leaks from pipelines caused by defective seams and welds were similar for both the old and new pipelines.

A large number of inspection and leak detection methods are available to detect pipeline corrosion damage (wall thinning, cracks, etc.) that can result in leaks. The main ones (see Table 51) are:

- Flow sampling (internal corrosion) - periodic
  - corrosion rate coupons
  - laboratory analysis of petroleum
  - miscellaneous trap monitoring (pig traps, strainers, etc.)
- Corrosion metering (internal corrosion) - continuous
  - corrosion rate probe
- Corrosion metering (external corrosion) and cathodic protection monitoring
  - potential measurements
  - continuity measurements
  - manufacturer recommendations
- Holiday detector (external corrosion) - periodic
- Visual inspection - periodic

- Standard non-destructive inspection equipment
  - active ultrasonics
  - X-ray
  - gamma ray
  - magnetic particle
  - ultrasonic imaging
  - eddy current
  - penetrants
- Pipeline inspection pigs
  - magnetic flux
  - active ultrasonics
  - TV camera
  - stereo pair
  - eddy current
  - electromagnetic noncontact transducer (EMAT)
  - manned inspections using standard NDI methods
- Other
  - passive acoustic array-acoustic emission.

External corrosion metering and monitoring of the pipeline cathodic protection is carried out on most United States pipelines (see DOT Regulation Title 49, 195.2 and 195.4). This has been highly successful in reducing corrosion damage and the leaks that result from corrosion. New techniques, such as those using computerized modeling, can define the potential profiles and the need for additional anode protection. Trend indications of internal pipeline corrosion can be obtained using flow sampling methods and corrosion rate probe.

Standard non-destructive inspection (NDI) equipment is commercially available for measuring actual corrosion damage. Active ultrasonic NDI equipment is highly accurate (better than 1 percent thickness to flaw size resolution) and reliable, and is often used for corrosion measurements. Costs of excavating for inspections or boring through the soil to the pipeline to provide contact of ultrasonic sensors to the line are quite high. Thus, this equipment is limited to inspections of only sample areas of the pipeline. High costs prevents this type of equipment from being considered as a practical way of significantly reducing pipeline petroleum leakage.

Only pipeline inspection pigs, used periodically, appear to have the potential of substantially reducing pipeline leaks caused by corrosion. This equipment provides excellent incipient failure detection of corrosion damage. The ultrasonic imaging inspection pig (see Table 53(g) and (o)) provides a 3-dimensional view of the inside of the pipeline wall. It potentially can detect all pipeline corrosion damage and eliminate most leaks caused by corrosion. The equipment has been successfully used on the Alyeska pipeline. However, ultrasonic imaging inspection pigs have not been developed to the extent that a device can be propelled through the pipeline by fluid flow; this development is necessary for practical application to most petroleum pipelines. Magnetic flux type inspection pigs (see Table 53(a)) are commercially available from AMF Tuboscope and Vetco. These devices have been used for a number of years and are capable of detecting most pipeline corrosion damage. TV camera inspection pigs and other devices can be used to complement the magnetic flux inspection by providing visual inspection of areas where interpretation of anomalies is uncertain.

A corrosion maintenance program used in conjunction with inspections and existing cathodic protection improves the effectiveness of corrosion prevention. For example, chemical inhibitors used at frequent intervals are effective in preventing internal corrosion.

5.3.2.7 Standard Non-Destructive Inspection--

A wide variety of standard non-destructive inspection equipment (Table 52) are available to periodically detect most pipeline system damage. Actual leakage, as well as internal and external damage that can lead to a leak, can be detected. Methods that are particularly sensitive to defects in petroleum pipeline systems and are in wide use include:

- Active ultrasonics
- X-ray
- Gamma ray
- Magnetic particle
- Ultrasonic imaging
- Eddy current
- Penetrants.

This equipment is effective and practical for inspecting pipelines under construction or above ground. Cost considerations make the equipment impractical for use on buried pipelines. Since most of the petroleum pipelines in the United States are buried, the use of this equipment is very limited. Thus, these methods are not considered viable solutions to significantly reducing the incidents or volume of spills.

5.3.2.8 Inspection Pigs--

In addition to detecting petroleum pipeline corrosion damage that can lead to leaks, inspection pigs detect other pipeline damage, such as defective pipeline seams, pipeline welds and pipeline leaks. Because of high cost, inspection pigs normally are used to inspect the line at intervals ranging from six months to five years. These devices have inspected over 100,000 miles of pipelines.

A variety of inspection pigs (Table 53) with different operating principles are available for internal inspection of the pipeline. Inspection pigs include magnetic flux, electromagnetic, kaliper, active ultrasonic passive ultrasonic, TV camera, nuclear, eddy current, ultrasonic imaging and infrared units. Most pigs are propelled through the pipeline by oil or other fluids flowing through the pipeline. A few types are pulled or pushed through the pipeline. In large-diameter pipelines, internal inspections can be carried out with inspectors. In this type of inspection, equipment and inspectors are propelled through the pipelines by vehicles ranging from a simple dolly manually pushed through the pipeline to a powered, controlled-environment inspection chamber with instrumentation trailer.

A pipeline cleaning pig, typically a brush type, and a dummy inspection pig are normally run through the pipeline prior to actually running the instrumented inspection pigs. A pipeline should be inspected with a pipeline inspection pig before the oil is initially transported to obtain background information. Calibration blocks for some types of inspection pigs are put on the pipeline to provide operational and sensitivity checks. Tracking systems for inspection pigs (Table 53(p)) are used in case the inspection pig gets stuck in the pipeline and for identifying defective areas.

The inspection pigs that are effective for detecting corrosion damage are also the most effective for detecting other internal pipeline damage. Five types of inspection pigs appear to be particularly effective. They are:

- Magnetic flux Table 53(a)
- Kaliper Table 53(b)
- Active ultrasonics Table 53(c)
- Ultrasonic imaging Table 53(g)
- EMAT Table 53(h).

A low-cost active ultrasonic device for detecting wall thickness only was recently under development by Harry Diamond Laboratories for inspection of U.S. Navy pipelines. The ultrasonic imaging inspection pig is capable of providing a 3-dimensional view of line defects. The device is not currently available for long lines or wide range of pipeline diameters.

The EMAT inspection pig is in the feasibility/experimental stage. Test results indicate that it can detect longitudinal stress corrosion cracks and non-localized regions of corrosion.

At this time only the magnetic flux and kaliper inspection pigs are available for widespread pipeline inspection. The magnetic flux inspection pig has been used to inspect over 50,000 miles of pipeline. However, the device is insensitive to longitudinal stress corrosion cracks and to non-localized regions of corrosion. The manufacturer claims this equipment to be 95 percent reliable in detecting pipeline defects. An example of the capability of the magnetic flux pig can be demonstrated by the results of an inspection carried out in a line (large-diameter 200-mile crude line) visited by project personnel during this study. In this case, the magnetic flux pig detected and located over 200 defects.

5.3.2.9 Survey-Pipeline System Charting and Depth of Burial--

Typical inspection methods for charting movements and measuring depth of burial and erosion of pipeline system components are given in Table 54. All methods except those in Table 54(h) are carried out periodically. None of these methods interfere with pipeline system operations.

Excessive movements of pipelines can cause abnormal stresses that may result in a leak. These movements are generally due to natural causes. Periodic inspections of pipeline movements provides data to chart the movement history of the line. This information can be used to determine whether excessive stressing of the line might be occurring and would allow remedial action to prevent damage. Methods (a) through (e) in Table 54 can provide such inspection. Of these, the radar and sonar methods appear to be the most effective and are low cost.

Maintaining pipeline depth of burial is extremely important in the prevention of pipeline damage from outside sources, particularly for underwater lines. Proper coverage of the pipeline minimizes damage that might occur from anchor dragging, machinery impacts, etc. The sonar method with penetrating and sub-bottom profiling is currently used on a number of underwater lines to effectively perform these inspections. Low-cost systems are commercially available. The radar method is one of several that can provide depth of burial inspections for onland pipelines.

In general, excessive scouring does not pose a great risk for most underwater lines and other components of pipeline systems. But inspections are necessary because of the disastrous effects, such as an offshore pumping platform collapse. Periodic inspections by divers are normally sufficient.

5.3.2.10 Miscellaneous Methods--

Inspection methods for petroleum pipeline systems that are not covered by the first nine categories are included in Table 55. One of these methods has the potential of significantly reducing oil pollution incidents. The others are either already required by existing regulations and are adequate, or have only very limited application.

The passive acoustic array has the potential of being the most effective of any leak detection and inspection method. It is intended to reduce the number of incidents of damage by outside forces. This is done by detecting acoustical sounds generated external to the line before the pipeline can be impacted and damaged by outside forces. The method can be adapted into existing supervisory control systems or it can be implemented as a separate system. Implementation would require either limited pipeline installation or retrofitting. The method is currently in the development stage.[a]

---

[a] Currently under development by NDE Technology, Inc.

Inspections of pipeline conditions such as overpressures and excessive shock load devices are essential to all pipeline systems. To be effective, these inspections should be carried out frequently, and systems should include alarms with suitable shutdown and relief devices. The United States has adequate regulations for these types of inspections.

A number of inspection methods such as given in (b), (e), and (h) of Table 55 can be effective in preventing shutdowns or for providing warnings of impending failures of various equipment. These methods may reduce maintenance costs, but are not effective in substantially reducing the oil spill risk because most pipelines have redundant or axuiliary equipment in the event of failure.

5.4 STATUS

5.4.1 Current Status of Leak Detection and Inspection Methods

The current status of the leak detection and inspection methods are identified on page . Status is separated into the following five phases:

- Required by U.S. regulation
- Common use
- State-of-the-art
- Developmental
- Feasibility.

5.4.2 Pipeline Regulations and Recommendations - U.S. and Foreign Countries

Liquid pipelines in the U.S. are regulated by two main agencies, the Department of Transporation and the Department of the Interior. Other U.S. Government agencies (some by delegation), such as the U.S. Coast Guard for deepwater ports[14], also regulate liquid lines. Many foreign countries such as the United Kingdom, Switzerland, Italy, the Netherlands and West Germany also regulate their liquid lines. In some areas, foreign regulations are more stringent than those in the U.S. In addition to existing regulations, trade organizations from private industry often recommend practices based on recent developments in industry.

Existing liquid pipeline inspection and leak detection regulations have been reviewed and recommendations made in a few recent studies. One study (Reference 51, pp. 4-1 through 4-301) sponsored by DOT provided a detailed review of regulations and industry recommendations of offshore and onland lines. Another study[71] sponsored jointly by DOT, DOE and DOI, reviewed inspection/testing/monitoring and regulations for offshore structures and liquid lines. Details of specific government agency jurisdictions are included in these reports and this information will not be repeated here. A third study[14] conducted for USCG and DOT provided recommendations of inspection methods and procedures for deepwater ports. Both onland and offshore lines were included in the study. An overall review of U.S. pipeline regulations is presented in Reference 1. The study identifies a number of significant problems and weaknesses in existing U.S. pipeline safety programs. No new regulations are specifically identified for the Alyeska pipeline, but there has been a substantial effort in minimizing the risk of serious spills. Studies with recommendations have been made and leak detection and inspection methods developed specifically for the Alyeska line. At this time, no in-depth report of this effort is publicly available.

U.S. regulations for liquid pipelines have helped to improve the accident record of the petroleum industry. These regulations are normally presently in the following six areas and are listed on page 197. Only two of these areas, operation and maintenance and pressure testing[a] are pertinent to this study. There are a number of reasons for emphasis in these areas; a few will be discussed. First, the main objective of this study is to recommend a viable and cost-effective spill prevention program that would significantly reduce spill incidents and volume. It is expected that this can be accomplished by implementing scheduled line inspections and/or leak detection. Implementation of a program that includes methods for the other four areas is not expected to significantly reduce spill volume because of the following: (a) current regulations; (b) recommendations by various pertinent organizations; and (c) oil company programs are already quite effective in preventing spills.

Spills normally occur after the line is designed, constructed and pressure-tested; and spill frequency depends on factors such as pipeline age. It is in this time frame that leak detection and inspection methods might effectively be used to prevent spills and minimize spill volume, and where a void exists with current practices in the U.S. Thus, existing regulations and recommendations for leak detection and inspection that pertain primarily to operation and maintenance[b] are reviewed in the subsections that follow. For comparison purposes, existing regulations and recommendations for gas lines are also included. Regulations of U.S. and foreign countries, recommendations, and also maintenance practices for a typical well-maintained pipeline are included in the subsections that follow.

Liquid Lines

- U.S. Regulations - Liquid Lines

1. DOT CFR 195. - U.S. Regulation LIQUID LINES

   49 CFR 195 - Part 195, Title 49 Code of Federal Regulations, Minimum Federal Safety Standards for Liquid Pipelines, appearing in 34 F. R. 15473, October 4, 1969, with ammendments up to and including Amdt. 195-14, Federal Register Vol 43, No. 84, May 1, 1978.

---

[a] There are no U.S. regulations for pressure testing in-service of existing operational lines.

[b] Other regulations, recommendations and review are provided in Appendix A and in the referenced studies.

AREAS OF LIQUID PIPELINE SYSTEMS UNDER U.S. GOVERNMENT REGULATIONS

GENERAL

Scope
Definitions
Matter incorporated by reference
Acceptable petroleum commodities
Transportation of certain commodities
Transportation of commodities in pipelines constructed with other than steel pipe
Responsibility of carrier for compliance with this part

ACCIDENT REPORTING

Scope
Telephonic notice of certain accidents
Accident reporting
Instructions for preparing DOT Form 7000-1
Changes in or additions to accident report
Carrier assistance in investigation
Supplies of accident report DOT Form 7000-1

DESIGN REQUIREMENTS

Scope
Design temperature
Variations in pressure
Internal design pressure
External pressure
External loads
New pipe
Used pipe
Valves
Fittings
Changes in direction: Provision for internal passage
Fabricated branch connections
Closures
Flange connection
Station piping
Fabricated assemblies
Above ground tanks

CONSTRUCTION

Scope
Compliance with specifications or standards
Inspection-general
Material inspection
Welding of supports and braces
Pipeline location
Bending of pipe
Welding: General
Welding, miter joints
Welding: Seam offset

CONSTRUCTION (Continued)

Welds: Filler metal
Welders: Testing
Welding: Weather
Welding: Arc burns
Welds and welding inspection: Standards of acceptability
Welds: Repair of defects
Welds: Removal of defects
Welds: Nondestructive testing and retention of testing records
External corrosion protection
External coating
Cathodic protection system
Test leads
Installation of pipe in a ditch
Cover over buried pipeline
Clearance between pipe and underground structures
Backfilling
Above ground components
Crossing of railroads and highways
Valves: General
Valves: Location
Pumping equipment
Above ground tanks
Construction records

PRESSURE TESTING

Scope
General requirements
Testing of components
Test medium
Testing of tie-ins
Records

OPERATION AND MAINTENANCE

Scope
General requirements
Maps and records
Maximum operating pressure
Communications
Line markers
Inspection of rights-of-way and crossings under navigable waters
Cathodic protection
External corrosion control
Internal corrosion control
Valve maintenance
Pipeline repairs
Pipe movement
Scraper and sphere facilities
Overpressure safety devices
Firefighting equipment
Storage vessels
Signs
Security of facilities
Smoking or open flames

EPA Form 2350-4 (4-80)
TYPING GUIDE SHEET

2. OCS #9 - U.S. Regulation LIQUID LINES

   OCS Order No. 9 - Oil and Gas Pipelines, established by the U.S. Department of the Interior, Geological Survey, Conservation Division. Gulf of Mexico Area, October 30, 1970.

- U.S. Recommendations - Liquid Lines

3. API - U.S. Recommendations LIQUID LINES

   API RP 1111, Recommended Practice for Design, Construction Operation and Maintenance of Offshore Hydrocarbon Pipelines, 1st Edition, March 1976, prepared by the Transportation Department of the American Petroleum Institute.

- Foreign Regulations - Liquid Lines

4. DnV - Foreign Regulations LIQUID LINES

   DnV - Rules for the Design, Construction and Inspection of Submarine Pipelines and Pipeline Risers, January 29, 1976, prepared by Det Norske Veritas, Norway.

- Foreign Recommendations - Liquid Lines

5. IP - Foreign Recommendations LIQUID LINES

   IP - "Supplement to IP Pipelines Code, Submarine Pipelines," Petroleum Pipelines Safety Code, published in 1974 with Supplements, prepared by the Institute of Petroleum, Great Britain.

- Well-Maintained and Inspected Pipelines - Liquid Lines

6. Practices by pipeline company A.

Gas Lines

- U.S. Regulations - Gas Lines

7. DOT CFR 192. - U.S. Regulation GAS LINES

   49 CFR 192 - Part 192, Title 49, Code of Federal Regulations, Minimum Federal Safety Standards for Gas Lines, appearing in 35 F.R. 13257, August 19, 1970, with amendments up to and including Amdt. 192-27A, 41 F.R. 47252, October 28, 1976.

- DOT CFR 191. - U.S. Regulation GAS LINES

  49 CFR 191 - Part 191, Title 49, Code of Federal Regulations, Leak Reporting Requirements for Gas Lines, appearing in 35 F.R. 320, January 8, 1970. (Also referred to as DOT regulation).

A list of legislation and regulations, standards technical requirements, codes of practice for design construction and operation of oil pipelines in Western Europe is included in Appendix A-2.

3.4.2.1 Visual and Visual Aided Line Observations for Leakage--

Liquid Lines

1. DOT (U.S. Regulation)

   CFR 195.412 "(a) Each carrier shall, at intervals not exceeding 2 weeks inspect the surface condition on or adjacent to each pipeline right-of-way.

   (b) Except for offshore pipelines, each carrier shall at intervals not exceeding five years, inspect each crossing under a navigable waterway to determine the condition of the crossing."

2. OCS #9 (OCS Order)

   1.E "All pipelines should be maintained in good operating condition and inspected monthly for indications of leakage using aircraft, floating equipment on other, methods."

3. API

   701.5 "Each pipeline operator should maintain a periodic pipeline patrol program to observe conditions along the pipeline route affecting the pipeline's safe operations."

4. DnV

   9.3.1.1 "The frequency and extent of surveys shall depend upon factors such as

   - type of survey
   - transportation of product
   - pipeline route (traffic density, depth of burial)
   - operation of pipeline systems
   - conditions of pipeline/riser as installed
   - degree of pipeline/riser exposure to potential damage and/or deterioration caused by corrosion, wear, etc.

   9.3.1.2 A periodic survey is normally to be carried out annually if not otherwise agreed upon in accordance with 9.3.1.1 above.

   9.3.1.3 The time for annual surveys may, under normal circumstances, be selected with due regard to weather conditions and operation of the pipeline (Frequency 12 ± 3 months).

   9.3.1.4 The society may, upon request accept a continuous survey in lieu of regular periodical surveys. Each part of the system is then to be controlled as frequently as in the case of regular periodical surveys.

9.3.1.5 The owner is to notify the society on occasions when such parts of the pipeline system, which are not normally assessible for survey, may be examined.

5. IP

11.9 "It is recommended that long submarine pipelines be inspected regularly by aerial patrol."

6. Pipeline Company A

Ground patrolling is intended to prevent any deteriorations in the line resulting from:

- vegetation, vultivation and construction inside the right-of-way.
- erosion phenomena (landslides, gullies formed by running water, etc.)
- the carrying out of various forms of work immediately near the right-of-way (drainage, irrigation ditches, pipe or cable laying, road building.
- this patrolling is carried out by hired staff; each line walker covers 12.4 miles which he inspects twice a month and keep in touch with various people who are likely to be aware of anomalies or incidents.

Ground patrolling is supplemented by special air patrol which is carried out about twice a month with low-flying aircraft.

Gas Lines

7. DOT (U.S. Regulation)

CFR 192.705(a) Each operator shall have a patrol program to observe surface conditions on and adjacent to the transmission line right-of-way for indications of leaks, construction activity, and other factors affecting safety and operation.

(b) The frequency of patrols is determined by the size of the line, the operating pressures, the class location, terrain, weather, and other relevant factors, but intervals between patrols may not be longer than prescribed in the following table:

Class location of line	Maximum interval between patrols At highway and railroad crossings	 At all other places
1,2	6 months	1 year
3	3 months	6 months
4	do	3 months

(Note: Offshore is Class 1)

49 CFR 192.706 "(a) Each operator of a transmission line shall provide for periodic leakage surveys of the line in its operating and maintenance plan.

(b) Leakage surveys of a transmission line must be conducted at intervals not exceeding 1 year. However, in the case of a transmission line which transports gas in conformity with § 192.625 without an odor or odorant, leakage surveys using leak detector equipment must be conducted--

(1) In Class 3 locations, at intervals not exceeding 6 months; and

(2) In Class 4 locations, at intervals not exceeding 3 months."

U.S. regulations of line observations at least every two weeks are justified. However, more frequent or more effective line observations depending upon factors such as volume of product transported, age of pipeline might be justified for some lines. For example, in South Europe, air patrolling is used, and a staff is employed to walk the lines.

5.4.2.2 Oil Spill Detectors on or Near the Water--

Liquid Lines

1. DOT (U.S. Regulation)

   No Regulation

2. OCS

   No OCS Order

3. API

   Not Discussed

4. DnV

   Not Discussed

5. IP

   Not Discussed

6. Pipelines Company A

   Not Discussed.

Gas Lines

NOT APPLICABLE

5.4.2.3 Leak Detection by Continuous or Periodic Monitoring of Internal Fluid Flow Variations during Product Transfer--

Liquid Lines

1. DOT

   No Regulation

2. OCS

   No OCS Order

3. API

   Not Discussed

4. DnV

   DnV 9.2.2.3 "It may be required that the product flow at delivering and receiving stations along the pipeline is measured continuously or at regular intervals for the purpose of leakage detection."

5. IP

   Not Discussed

6. Pipeline Company A

   - Any substantial leaks are detected by volume comparators in permanent operation. Communication equipment provides a permanent comparison of the oil flow rates recorded at relief stations and at delivery terminals. If the difference in volumes measured upstream and downstream from a given point exceeds a certain threshold, a visual and acoustic alarm is triggered.

Gas Lines

7. DOT (U.S. Regulation)

   No Regulation

5.4.2.4 Leak Detection and Location of Leaked Oil on or at a Short Distance from Line--

1. DOT (U.S. Regulation)

   No Regulation

2. OCS

   No OCS Order

3. API

Not Discussed

4. DnV

5. IP

6. Pipeline Company A

Metal rods, attached to the pipelines by brazing at approximate intervals of 500 m (1,640.5 ft) permit the localization of leaks monitoring of the oil flow carried out systematically by means of appropriate equipment.

5.4.2.5 Leak Detection by Periodic Pressure Testing of Existing Pipeline Systems--

Liquid Lines

1. DOT (U.S. Regulations)

No regulations of in-service oil pipelines. There are regulations (see CFR 195.3) for newly constructed replaced or otherwise changed.

2. OCS

No OCS Order

3. API

Not Discussed

4. DnV

See Section 5.4.1.5

5. IP

IP 9.2 "When the pipeline is not in operation, it is recommended that it be shut down under pressure, except on occasions when the shut-down has been arranged to allow maintenance on the line and a careful record made of the pressure during the shut-down period.

If the pipeline crosses areas where there are particular dangers of water pollution being caused by any leakage, then a static pressure test as described above should be arranged over a period of 24 hours once per year."

6. Pipeline Company A

Very small leaks, which have limited immediate consequences but the effects of which may be noticed for a substantial period, are detected by:

- differential pressure measurements between various sections of the pipeline.

This inspection involves the periodic verification that pipelines are leakproof, by means of hydrostatic tests on each of the sections located between block valves (located 12.4 to 15.5 miles apart).

Gas Lines

7. DOT (U.S. Regulation)

49 CFT 192.743 Pressure limiting and regulating stations: testing of relief devices -

"(a) If feasible, pressure relief devices (except rupture discs) must be tested in place, at intervals not exceeding 1 year, to determine that they have enough capacity to limit the pressure on the facilities to which they are connected to the desired maximum pressure.

(b) If a test is not feasible, review and calculation of the required capacity of the relieving device at each station must be made, at intervals not exceeding one year, and these required capacities compared with the rated or experimentally determined relieving capacity of the device for the operating conditions under which it works.

(c) If the relieving device is of insufficient capacity, a new or additional device must be installed to provide the additional capacity required."

8. DOT (U.S. Regulation)

No Regulation

5.4.2.6 Corrosion Inspection--

5.4.2.6.1 Corrosion Inspection and Maintenance - Atmospheric

Liquid Lines

1. DOT (U.S. Regulation)

49 CFR 195.416"(D) Each carrier shall, at intervals not exceeding 5 years, electrically inspect the bare pipe in its pipeline system that is not cathodically protected and must study leak records for that pipe to determine if additional protection is needed.

(e) Whenever any buried pipe is exposed for any reason, the carrier shall examine the pipe for evidence of external corrosion. If the carrier finds that there is active corrosion, that the surface of the pipe is generally pitted, or that corrosion has caused a leak, it shall investigate further to determine the extend of the corrosion.

(f) Any pipe that is found to be generally corroded so that the remaining wall thickness is less than the minimum thickness required by the pipe specification tolerances must either be replaced with coated pipe that meets the requirements of this part or, if the area is small, must be repaired. However, the carrier need not replace generally corroded pipe if the operating pressure is reduced to be commensurate with the limits on operating pressure specified in this subpart, based on the actual remaining wall thickness.

(g) If isolated corrosion pitting is found, the carrier shall repair or replace the pipe unless--

(1) The diameter of the corrosion pits, as measured at the surface of the pipe, is less than the nominal wall thickness of the pipe; and

(2) The remaining wall thickness at the bottom of the pits is at least 70 percent of the nominal wall thickness.

(h) Each carrier shall clean, coat with material suitable for the prevention of atmospheric corrosion, and, maintain this protection for, each component in its pipeline system that is exposed to the atmosphere."

2. OCS

No OCS Order

3. API

API 801.3 "Carbon steel pipe, valves and fittings exposed to the atmosphere should be protected with an external coating, when such protection is necessary."

4. DnV

Not Discussed

5. IP

Not Discussed

6. Pipeline Company A

Not Discussed

Gas Lines

7. DOT (U.S. Regulation)

No Regulation

8. DVT (U.S. Regulation)

No Regulation

5.4.2.6.2 Internal Corrosion Control

Liquid Lines

1. DOT (U.S. Regulation)

49 CFR 195.418 "(a) No carrier may transport any commodity that would corrode the pipe or other components of its pipeline system, unless it has investigated the corrosive effect of the commodity on the system and has taken adequate steps to mitigate corrosion.

(b) If corrosion inhibitors are used to mitigate internal corrosion the carrier shall use inhibitors in sufficient quantity to protect the entire part of the system and shall also use coupons or other monitoring equipment to determine their effectiveness.

(c) The carrier shall, at intervals not exceeding 6 months, examine coupons or other types of monitoring equipment to determine the effectiveness of the inhibitors or the extent of any corrosion.

(d) Whenever any pipe is removed from the pipeline for any reason, the carrier must inspect the internal surface for evidence of corrosion. If the pipe is generally corroded such that the remaining wall thickness is less than the minimum thickness required by the pipe specification tolerances, the carrier shall investigate adjacent pipe to determine the extent of the corrosion. The corroded pipe must be replaced with pipe that meets the requirements of this part or, based on the actual remaining wall thickness, the operating pressure must be reduced to be commensurate with the limits on operating pressure specified in this subpart."

2. OCS

No OCS Order

3. API

API 803 "NANCE RP-01-75 should be used to determine the need for design, installation and evaluation of the results of an internal corrosion mitigation program. Where necessary, internal corrosion may be mitigated by one or more of the following: pipeline scraping, pigging, or sphering at regular intervals, dehydration, inhibition, bactericides, oxygen scavangers, and pipeline internal coating. The variables and severity of each case will determine the preventive methods that should be used. A monitoring program should be established to evaluate the results of internal corrosion mitigation systems."

4. DnV

DnV 6.6.1.1 "Internal protection is to be considered for pipelines and risers which during installation or operation may be subject to corrosion. Information about the possibilities of internal corrosion is to be submitted for evaluation. Treatment of the product to be transported may be utilized as a means of controlling corrosion, likewise pigging at regulat intervals and corrosion monitoring."

5. IP

IP 8.1 "The operation of pipelines depends to a large extent upon the nature of the fluids being handled, and each operator should formulate a procedure for safe pipeline operation. Particular emphasis should be laid upon the following:

(e) Prevention of internal corrosion."

6. Pipeline Company A

Experience has shown that in the case of crude oil pipelines, internal corrosion is practically non-existant on account of the products transported. However, as a precaution, "corrosion detectors" are installed at 62.1 mile intervals and examined once every year.

Gas Lines

7. DOT (U.S. Regulation)

49 CFR 192.475 "(a) After July 31, 1972, corrosive gas may not be transported by pipeline, unless the corrosive effect of the gas on the pipeline has been investigated and steps have been taken to minimize internal corrosion.

(b) Whenever any pipe is removed from a pipeline for any reason, the internal surface must be inspected for evidence of corrosion. If internal corrosion is found--

(1) The adjacent pipe must be investigated to determine the extent of internal corrosion;

(2) Replacement must be made to the extent required by the applicable paragraphs of § 192.485, § 192.487, or § 192.489; and

(3) Steps must be taken to minimize the internal corrosion.

(c) Gas containing more than 0.1 grain of hydrogen sulfide per 100 standard cubic feet may not be stored in pipe-type of bottle-type holders."

49 CFR 192.77 "If corrosive gas is being transported, coupons or other suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion. After July 31, 1972, each coupon or other means of monitoring internal corrosion must be checked at intervals not exceeding 6 months."

8. DOT (U.S. Regulation)

No Regulation

5.4.2.6.3 Cathodic Protection System-External

Liquid Lines

1. DOT (U.S. Regulation)

49 CFR 195.414 "(a) After March 31, 1973, no carrier may operate a pipeline that has an external surface coating material, unless that pipeline is cathodically protected. This paragraph does not apply to tank farms and buried pumping station piping.

(b) Each carrier shall electrically inspect each bare pipeline before April 1, 1975, to determine any areas in which active corrosion is taking place. The carrier may not increase its established operating pressure on a section of bare pipeline until the section has been so electrically inspected. In any areas where active corrosion is found, the carrier shall provide cathodic protection. Section 195.416 (f) and (g) applies to all corroded pipe that is found.

(c) Each carrier shall electrically inspect all tank farms and buried pumping station piping before April 1, 1973, as to the need for cathodic protection, and cathodic protection shall be provided where necessary.

(d) Notwithstanding the deadline for compliance in paragraphs (a), (b), and (c) of this section, this section does not apply to offshore pipelines located between a production facility and a carrier's trunkline reception point until August 1, 1977."

49 CFR 195.416 External Corrosion Control-

"(a) Each carrier shall, at intervals not exceeding 12 months, conduct tests on each underground facility in its pipeline system that is under cathodic protection to determine whether the protection is adequate."

2. OCS

No OCS Order

3. API

API 804 "The cathodic protection system should be maintained in accordance with the recommendation in NACF RP-06-75. The effectiveness of the cathocis protection system should be evaluated at least annually. Voltage and current output of impressed current systems should be verified and recorded at two-month intervals. Interference bonds, where failure would jeopardize pipeline protection, should be checked for proper operation at two-month intervals."

4. DnV

DnV 9.3.2.2 "Control of the performance of the cathodic protection system is required. The extent of such testing may be reduced to scrutinizing of the Owner's potential measurement reports. If found necessary, potential measurements are to be conducted at the discretion of the Surveyor and in accordance with 8.8.3."

5. IP

IP 8.1 "The operation of pipelines depends to a large extent upon the nature of the fluids being handled, and each operator should formulate a procedure for safe pipeline operation. Particular emphasis should be laid upon the following: (f) Regular checking of the cathodic protection installation."

IP 7.5.4 Operation and Maintenance-

"Regular attention to current consumption figures at each installation is essential. Adequate protection depends almost entirely on maintaining the safety level of pipe-to-soil potential along the whole route. Pipe-to-soil measurements should be taken at least annually or whenever an abnormal condition is indicated. Highly corrosive areas should receive special attention. In addition, the pipe-to-soil potential of other structures crossing the pipeline route should be checked for any adverse changes, whether or not they are bonded into the cathodic protection system."

6. Pipeline Company A

The pipelines must be effectively protected against external corrosion by means of:

- Passive protection provided by appropriate coatings;
- Active protection provided by a cathodic protection system.

In order to verify the satisfactory operation of these units and consequently the effectivensss of the cathodic protection, 250 "potential measuring points" have been installed, especially at intersections with buried metal pipes and at large crossings. The line is protected against corrosion by keeping it at a negative potential with respect to the soil. This negative potential is maintained by means of a system including supply stations, which are checked every month, and insulating joints located up and downstream of the pumping stations, upstream of the delivery points and the crossings of large rivers.

Gas Lines

7. DOT (U.S. Regulation)

49 CFR 192.475 "(a) Each pipeline that is under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meeting the requirements of § 192.463. However, if tests at those intervals are impractical for separately protected service lines or short sections of protected mains, not in excess of 100 feet, these service lines and mains may be surveyed on a sampling basis. At least 10 percent of these protected structures, distributed over the entire system, must be surveyed each calendar year, with a different 10 percent checked each subsequent year, so that the entire system is tested in each 10-year period.

(b) At intervals not exceeding 2 months, each cathodic protection rectifier or other impressed current power source must be inspected to ensure that it is operating.

(c) At intervals not exceeding 2 months, each reverse current switch, each diode, and each interference bond whose failure would jeopardize structure protection, must be electrically checked for proper performance. Each other interference bond must be checked at least once each calendar year, but with intervals not exceeding 15 months.

(d) Each operator shall take prompt remedial action to correct any deficiencies indicated by the monitoring.

(e) After the initial evaluation required by paragraphs (b) and (c) of §192.455 and paragraph (b) of §192.457, each operator shall, at intervals not exceeding 3 years, reevaluate its unprotected pipelines and cathodically protect them in accordance with this subpart in areas in which active corrosion is found. The operator shall determine the areas of active corrosion by electrical survey, or where electrical survey is impractical, by the study of corrosion and leak history records, by leak detection survey, or by other means."

8. DOT (U.S. Regulation)

No Regulation

5.4.2.6.4 Chemical Monitoring

Liquid Line

1. DOT (U.S. Regulation)

   No Regulation

2. OCS

   No OCS Order

3. API

   Not Discussed

4. DnV

   DnV 9.2.2.2 "It may be required that the concentrations of various chemical or physical components in the product are measured and recorded at regular intervals."

5. IP

   Not Discussed

6. Pipeline Company A

   Not Discussed

Gas Lines

7. DOT (U.S. Regulation)

   No Regulation

8. DOT (U.S. Regulation)

   No Regulation

5.4.2.7 Standard Non-Destructive Inspections to Check Integrity of Pipeline (Flaws, Cracks, Buckling, Dents and Other Potential Failure Conditions)--

Liquid Lines

1. DOT (U.S. Regulation)

   49 CFR 195.418 "(d) Whenever any pipe is removed from the pipeline for any reason, the carrier must inspect the internal surface for evidence of corrosion. If the pipe is generally corroded such that the remaining wall thickness is less than the minimum thickness required by the pipe specification tolerances, the carrier shall investigate adjacent pipe to determine the extent of the corrosion. The corroded pipe must be replaced with pipe that meets the requirements of this part or, based on

the actual remaining wall thickness, the operating pressure must be reduced to commensurate with the limits on operating pressure specified in this subpart."

2. OCS

No OCS Order

3. API

Not Discussed

4. DnV

Not Discussed

5. IP

IP II.10 "Regular underwater inspection should be carried out where there is risk of damage to the pipeline or where scour conditions may occur."

6. Pipeline Company A

Not Discussed

Gas Lines

7. DOT (U.S. Regulation)

Not Discussed

8. DOT (U.S. Regulation)

Not Discussed

5.4.2.8 Inspection Pigs to Check the Integrity of Pipeline (Flaws, Cracks, Buckling, Dents and Other Potential Failure Conditions)--

Liquid Lines

1. DOT (U.S. Regulation)

No Regulations

2. OCS

No OCS Orders

3. API

Not Discussed

4. DnV

DnV 9.3.2.3 "Inspection by gauging-pig (e.g., caliper-pig is required for detection of buckles or dents in the pipeline/riser."

DnV 9.3.2.5 "Thickness measurements may be required where there is reason to believe that the pipe wall thickness is being reduced due to external/internal corrosion or internal erosion (e.g., the effect of sand content in the transported gas).

5. IP

IP II.10 "Regular underwater inspection should be carried out where there is risk of damage to the pipeline or where scour conditions may occur."

6. Pipeline Company A

Not Discussed

Gas Lines

1. DOT (U.S. Regulation)

No Regulations

8. DOT (U.S. Regulation)

No Regulations

5.4.2.9 Survey-Pipeline Systems Charting and Depth of Burial--

Liquid Lines

1. DOT (U.S. Regulation)

49 CFR 195.404 "(a) Each carrier shall maintain current maps and records of its pipeline systems that include at least the following information:

(1) Location and identification of all major facilities.

(2) All crossings of public roads, railroads, rivers, buried utilities, and foreign pipelines.

(3) The maximum operating pressure of each pipeline.

(4) The diameter, grade, type, and nominal wall thickness of the pipe.

(b) Each carrier shall maintain daily operating records that indicate the discharge pressures at each pump station and any unusual operations of a facility. The carrier shall retain these records for at least 3 years.

(c) Each carrier shall also maintain for the useful life of that part of the pipeline system to which they relate, records that include the following:

(1) The date, location, and description of each repair made to its pipeline systems.

(2) A record of each inspection and each test required by this subpart."

2. OCS

OCS #9, 1.A "The operator shall be responsible for the installation of the following control devices on all oil and gas pipelines connected to a platform including pipelines which are not operated or owned by the operator... The operator shall submit records semi-annually showing the present status and past history of each device, including dates and details of inspection, testing, repairing, adjustment, and reinstallation."

OCS #9, 1.E "... records of these inspections including the date, methods and results of each inspection shall be maintained by the pipeline operator and submitted annually by April 1 ..."

3. API

API 703 "The following records should be maintained for operations and maintenance purposes:

(a) Material and construction specifications.
(b) Route maps and alignment sheets.
(c) Coating and cathodic protection specifications.
(d) Pressure test data.
(e) Non-destructive inspection data.
(f) Necessary operational data.
(g) Pipeline patrol records.
(h) Corrosion mitigation records recommended in 805.1.
(i) Leak and break records and failure investigation records.
(j) Records of safety equipment inspection.
(k) Records of other inspections, such as external or internal pipe conditions when line is cut or hot tapped.

The records recommended in (e), (f), (g) and (j) should be retained for at least one year. Other recommended records should be retained for the life of the facility unless states otherwise in this Recommended Practice."

4. DnV

DnV 9.2.3.2 "Files on Owner's inspection reports are to be available in connection with surveys required by the Society."

DnV 9.2.3.3 "The Society's requirements for maintenance and repair will be based on information obtained from periodical surveys and special surveys if applicable."

5. IP

IP II.10 "Regular underwater inspection should be carried out where there is risk of damage to the pipeline or where scour conditions may occur."

6. Pipeline Company A

Not Discussed

Gas Lines

7. DOT (U.S. Regulation)

49 CFR 192.709 "Each operator shall keep records covering each leak discovered, repair made, transmission line break, leakage survey, line patrol, and inspection, for as long as the segment of transmission line involved remains in service."

8. DOT (U.S. Regulation)

No Regulation

5.4.2.10 Miscellaneous-Leak Detection and Prevention by Equipment Inspection--

Liquid Lines

1. DOT (U.S. Regulation)

No regulations for oil lines. There are line regulations for liquefied gases as follows:

DOT CFR 195.428"(a) Except as provided in paragraph (b) of this section, each carrier shall, at intervals not exceeding 12 months, or 6 months in the case of pipelines used to carry liquefied gages, inspect and test each pressure limiting device, relief valve, pressure regulator, or other item of pressure control equipment to determine that it is functioning properly, is in good mechanical condition, and is adequate frum the standpoint of capacity and reliability of operation for the service in which it is used.

(b) In the case of relief valves on pressure storage vessels containing liquefied gas, each carrier shall test each valve at intervals not exceeding 5 years."

2. OCS

No OCS Order

3. API

Comments on safety equipment on nonproduction platforms are presented in 701.6.

4. DnV

Not Discussed

5. IP

Not Discussed

6. Pipeline Company A

Block valves are housed inside a sealed casing in order to avoid any contamination of the surrounding area.

A center is provided with data concerning the hydraulic condition of the pipelines and the position of each of the block-valves, which can be shut by remote control for safety reasons.

Gas Lines

7. DOT (U.S. Regulation)

49 CFR 192.706 "(a) Each operator of a transmission line shall provide for periodic leakage surveys of the line in its operating and maintenance plan.

(b) Leakage surveys of a transmission line must be conducted at intervals not exceeding 1 year. However, in the case of a transmission line which transports gas in conformity with §192.625 without an odor or odorant, leakage surveys using leak detector equipment must be conducted:

(1) In Class 3 locations, at intervals not exceeding 6 months; and
(2) In Class 4 locations, at intervals not exceeding 3 months.

5.4.2.11 Miscellaneous-Safety Equipment and Pressure Limiting and Relieving Devices--

Liquid Lines

1. DOT (U.S. Regulation)

49 CFR 195.426 Scraper and Sphere Facilities-

"No carrier shall use a launcher or receiver that is not equipped with a relief device capable of safely relieving pressure in the barrel before insertion or removal of scrapers or spheres. The carrier must use a suitable device to indicate that pressure has been relieved in the barrel or must provide a means to prevent insertion or removal of scrapers or spheres if pressure has not been relieved in the barrel."

49 CFR 195.428 Overpressure Safety Devices-

"(a) Except as provided in paragraph (b) of this section, each carrier shall, at intervals not exceeding 12 months, or 6 months in the case of pipelines used to carry liquefied gases, inspect and test each pressure limiting device, relief valve, pressure regulator, or other item of pressure control equipment to determine that it is functioning properly, is in good mechanical condition, and is adequate from the standpoint of capacity and reliability of operation for the service in which it is used.

(b) In the case of relief valves on pressure storage vessels containing liquefied gas, each carrier shall test each valve at intervals not exceeding 5 years."

2. OCS

No OCS Order

3. API

API 701.6 Safety Equipment on Non-Production Platforms-

"Pressure limiting devices, relief valves, automatic shutdown valves, and other safety devices, except check valves should be subjected to periodic inspections at a maximum interval of six months. The inspection should verify that the device is in good mechanical condition and properly performs the safety function for which it was installed.

4. DnV

DnV 9.3.2.6 "Pressure limiting devices, relief valves, automatic shutdown valves and other safety devices should be tested and inspected. The inspection should verify that the device is in good mechanical condition and properly performs the safety function for which it was installed."

5. IP

IP 8.1(a) "Safety devices for protecting the pipeline from pressures in excess of those for which it was designed."

IP 8.1(b) "Instruments to give warning and shut down pumps in case of damage caused to the pipeline by Act of God or third party activities.

6. Pipeline Company A

Each valve is housed inside a sealed casing in order to avoid any contamination of the surrounding area.

Gas Lines

7. DOT (U.S. Regulation)

49 CFR 192.731 Compressor Stations: Inspection and Testing of Relief Devices:

(a) Except for rupture discs, each pressure relieving device in a compressor station must be inspected and tested in accordance with §§192.739 and 192.743, and must be operated periodically to determine that it opens at the correct set pressure.

(b) Any defective or inadequate equipment found must be promptly repaired or replaced.

(c) Each remote control shutdown device must be inspected and tested, at intervals not to exceed 1 year, to determine that it functions properly."

49 CFR 192.737 Pipe-Type and Bottle-Type Holders: Plan for Inspection and Testing-

"(c) The pressure control and pressure limiting equipment must be inspected and tested periodically to determine that it is in a safe operating condition and has adequate capacity."

49 CFR 192.739 Pressure Limiting and Regulating Stations: Inspection and Testing-

"Each pressure limiting station, relief device (except rupture discs), and pressure regulating station and its equipment must be subjected, at intervals not exceeding 1 year, to inspections and tests to determine that it is:

(a) In good mechanical condition;
(b) Adequate from the standpoint of capacity and reliability of operating for the service in which it is employed;
(c) Set to function at the correct pressure; and
(d) Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation."

49 CFR 192.743 Pressure Limiting and Regulating Stations: Testing or Relief Devices-

"(a) If feasible, pressure relief devices (except rupture discs) must be tested in place, at intervals not exceeding 1 year, to determine that they have enough capacity to limit the pressure on the facilities to which they are connected to the desired maximum pressure.

(b) If a test is not feasible, review and calculation of the required capacity of the relieving device at each station must be made, at intervals not exceeding one year, and these required capacities compared with the rated or experimentally determined relieving capacity of the device for the operating conditions under which it works.

(c) If the relieving device is of insufficient capacity, a new or additional device must be installed to provide the additional capacity required."

8. DOT (U.S. Regulation)

No Regulation

5.4.2.12 Pipe Maintenance

1. DOT (U.S. Regulation)

49 CFR 195.402 General Requirements-

"(b) No carrier may operate or maintain its pipeline systems at a level of safety lower than required by this subpart and the procedures it is required to establish under paragraph (a) of this section.

(c) Whenever a carrier discovers any condition that could adversely affect the safe operation of its pipeline system it shall correct it within a reasonable time. However, if the condition is of such a nature that it presents an immediate hazard to persons or property, the carrier may not operate the affected part of the system until it has corrected the unsafe condition."

49 CFR 195.422 Pipeline Repairs-

"(a) Each carrier shall, in repairing its pipeline systems, insure that the repairs are made in a safe manner and are made so as to prevent damage to persons or property.

(b) No carrier may use any pipe, valve, or fitting, for replacement in repairing pipeline facilities, unless it is designed and constructed as required by this part."

2. OCS

No OCS Order

3. API

API 701.1 "Written starting, operating and shutdown procedures for pipeline facilities should be established and the operating company should take appropriate steps to see that these procedures are followed. These procedures should outline preventive measures and system checks as required to provide for the proper functioning of safety, control and alarm equipment."

4. DnV

DnV 9.1.2.1 "If it is found that the pipeline/riser in some way does not meet the Rules, the Society will require improvements, new surveys, or other measures found necessary in order to retain the Certificate of Approval, regardless of previous approvals."

DnV 9.2.3.1 "The Owner should provide such running inspection of the pipeline system as to initiate maintenance work necessary to retain the built-in safety."

DnV 9.3.2.1 "Survey of exposed parts of the pipeline, i.e., not buried parts, is required to verify that no unacceptable damages have occured to the pipe, the corrosion protection system, or the weight coating (anchoring system)."

5. IP

IP 9.3 "It is not always necessary to empty and gasfree a pipeline or to use water plugs in order to carry out maintenance or repair work which involves cutting and re-welding the line. These operations may be safely performed provided that the right conditions have been achieved."

6. Pipeline Company A

Not Discussed

Gas Lines

7. DOT (U.S. Regulation)

49 CFR 192.631 "(a) Each operator shall have a procedure or continuing surveillance of its facilities to determine and take appropriate action concerning changes in class location, failures, leakage history, corrosion, substantial changes in cathodic protection requirements, and other unusual operating and maintenance conditions.

(b) If a segment of pipeline is determined to be in unsatisfactory condition but no immediate hazard exists, the operator shall initiate a program to recondition or phase out the segment involved, or, of the segment cannot be reconditioned or phased out, reduce the maximum allowable operating pressure in accordance with § 192.619 (a) and (b)."

8. DOT (U.S. Regulation)

Not Discussed

SECTION 6

ANALYSIS OF THE RISK OF ACCIDENTAL OIL SPILLS FROM PETROLEUM PIPELINE SYSTEMS

An analysis of the risk of accidental oil spills from petroleum pipeline systems is carried out in this section. Both the risk that oil can spill from a system and environmental problems created by spillage are examined. First, the seriousness of oil spills is discussed in Section 6.1. Then the difficulties in assessing the risk of oil spills are reviewed in Section 6.2. Approaches accounting for these difficulties are presented. Finally, an analysis and assessment of the risk of oil spills was carried out in Section 6.3.

Since the risk of oil spills and the potential for risk reduction were both found to be much greater for line pipe than for any other pipeline system component, an in-depth analysis of the risk of oil spills from line pipe was carried out in Section 6.3. An analysis was performed on a reference line (typical line), and correction factors for variations from the reference line were developed so that the spill risk (potential) could be established for most lines. Simplified tables and figures were provided to enable an operator to estimate the spill potential of his own line.

6.1 SERIOUSNESS OF OIL SPILLS

Petroleum pipeline systems and line pipe, in particular, present a continuous potential for serious accidents and spills. Spills are expected to increase as the U.S. liquid pipeline system ages[a]. These are the obvious conclusions when data from accidental spills (Section 4.5.2) and individual accident reports are examined and oil spill risks evaluated (Appendix D). This situation exists even though petroleum pipeline transportation systems produce relatively few reported spills for the large quantities of oil transported.

Accidental spills are a serious matter and are detrimental to both the national interest and the oil and gas industries. The major problems created by these spills are:

- Subject segments of the population to potential catastrophies.
- Cause significant environmental damage.
- Cause losses of large quantities of petroleum.

---

[a] Average age of the U.S. liquid pipeline increases yearly.

Responsibility for the spill problem rests with both the government and operating companies, who must use the best means available to minimize the frequency and volume of spills and the resultant spill damage.

Various sources contribute to serious accidents in the petroleum pipeline system. Some of the major ones include:

- Properties and characteristics of the petroleum itself create serious hazards (even losses of small quantities, i.e., few barrels, can cause serious damage in some situations).
- Large volumes of petroleum transported through the system potentially can result in large volumes of petroleum spilled.
- Inadequacies and/or limitations in the spill prevention and detection measures.
- Variety of causes and types of pipeline system failures.

The potential for serious accidents is magnified when pipeline systems are located in or near high-risk areas. Some of these are:

- High population density
- Heavy industrial areas
- Commercial areas
- Underground water supplies
- Underground facilities
- Offshore.

Although petroleum pipeline systems are relatively safe, serious spills can and do occur for a variety of reasons. For example, large volumes of petroleum are transported using lines that are not under continuous surveillance. This can result in large volumes of hazardous fluids (thousands of barrels) being spilled before the spill is detected and the line shut down. Since explosions from crude and petroleum lines have occurred hundreds of feet from a break[58], the possibility exists, primarily in populated areas (urban, commercial, industrial), for exposure of large numbers of people and large amounts of property to potential hazards. The serious problems that exist can be emphasized by examining a few case histories. In the city of Los Angeles, for example, a network exists of approximately 200 miles of pipelines owned by 32 oil companies. One line which runs beneath a school ruptured and exploded in 1976 and eight persons were killed[72]. In another case, a crude leak caused an explosion near a heavily traveled freeway. Fortunately, this crude line did not cause leaks in the gas and product transmission lines located a short distance away. Other serious problems such as damage to water supplies are also possible. A recent study[46] indicates that serious spill hazards to undergound water supplies exist and identifies numerous cases of damage to underground water sources. The hundreds of serious spills that have occurred within the last ten years conclusively illustrates the potential for serious spills.

These types of serious spills are often considered as highly improbable, but serious accidents often do not follow statistical probabilities. The nuclear powerplant accident in Pennsylvania in early 1979 and the explosion of the almost empty crude oil tanker in the Los Angeles Harbor in 1978 are dramatic examples of highly improbable accidents. In the ship explosion, a number of fatalities occurred and windows were broken by the blast pressure wave at distances up to ten miles. In the nuclear reactor accident, segments of the community were evacuated as a precautionary measure.

Comparisons are often made, such as in Figure 48, of the relative safety of pipeline systems to other modes of transportation. Such comparisons are often misleading. For example, the significance of comparing auto fatalities with pipeline fatalities is questionable. At least 95 percent of the U.S. population routinely uses automobiles, and thus the expected fatalities are high. However, only a small percentage of the population use pipeline facilities or are in close proximity to lines. A further examination of the auto fatalities actually reveals that gasoline is the cargo most frequently responsible for highway deaths (about 10 percent). This latter information acutually demonstrates the hazard potential of petroleum spills. If one were to use other comparisons such as the potential of a major catastrophe from a single accident, the results would be less favorable for pipeline systems.

6.2 PROBLEMS IN ASSESSING THE OIL SPILL RISK

It is difficult to assess quantitatively the actual oil spill risk from U.S. petroleum pipeline systems. There are a number of reasons for this. The main reasons are:

- Oil spills can result in a variety of risks that must properly be identified and categorized.
- No industry standards exist for comparing and evaluating spill risks.
- Limited information is available on oil spill statistics.
- Limited information on the variations of the complex pipeline systems.
- Lack of suitable analysis scheme for variations of pipeline systems.

These major difficulties can be accounted for. Each will be discussed separately in the subsections that follow.

6.2.1 Identification and Categorization

Oil spills can result in a variety of significant risks such as the substantial loss of petroleum and serious problems external to the line. These risks must be properly identified and categorized to insure suitable analysis of the problem so that needed spill prevention and control can be identified. To satisfy these objectives, risks have been separated into the following two categories:

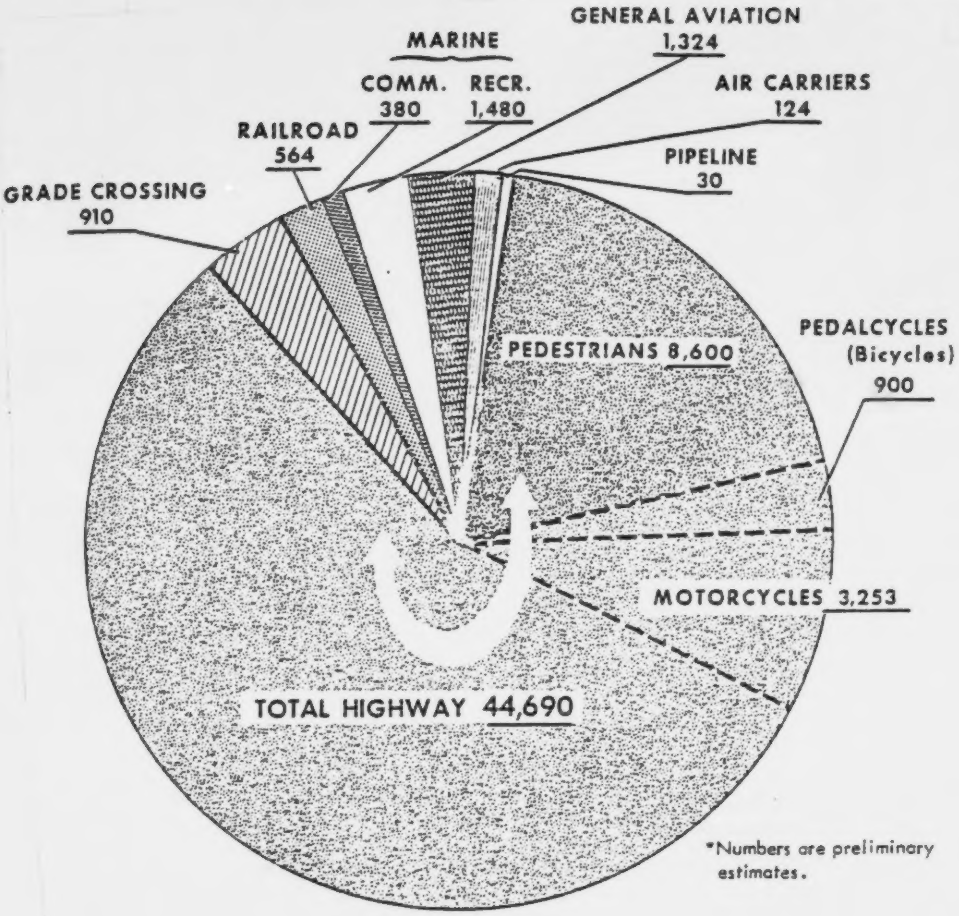


Figure 48. Transportation accidents in 1975, National Transportation Safety Board 1975.

- Risks that oil will escape from the pipeline system by accidental spillage.
- Risks external to the pipeline system after petroleum escapes from the line.

The first risk category deals primarily with the actual loss of petroleum from the line. The risk, in general, is independent of line location. The specific risks of spill incidents and spill volume can be determined from nationwide oil spillage statistics that are based on most lines. Also, the spill reduction capabilities of the available inspection and leak detection methods can be established for the line itself. These spill reduction capabilities are generally not dependent on line location.

The second category deals with additional risks, such as property damage or injuries that exist external to the pipeline system. These risks, in general, are dependent on line location. Hence, this category enables one to identify the various additional risks that may be characteristic of a particular location. High-risk areas, for example, can be identified and the extent of risk determined; the need for more effective spill prevention methods can be established and the increases in cost effectiveness of the various options can be determined.

6.2.2 Comparison and Evaluation

There are no industry standards for comparing and evaluating the risk that oil will escape from the pipeline system and risks external to the line by accidental spillage. However, a variety of suitable means do exist for assessing this risk.

6.2.2.1 Discussion of Risk of Oil Escaping from Pipelines--

We have selected two means that are most meaningful and practical in this study for comparing and evaluating the risk that oil will escape from the pipeline system. These are often used in oil, gas, and other industries.

The first means is to determine the risk of oil spills based on two criteria:

- Frequency or probability that a spill may occur;
- Quantity of oil spilled.

Both of these are important. For example, the severity of spill accidents based on injuries and property damage correlates almost directly with quantity spilled, Figure 49. The frequency of spills is of significance, particularly in areas of high risk; in many areas even a small spill can be extremely hazardous.

The second means, and the most meaningful, is to provide a measure of the relative risk that accounts for both the frequency and volume of spills. This is done by assessing the product (barrels per year) of the expected

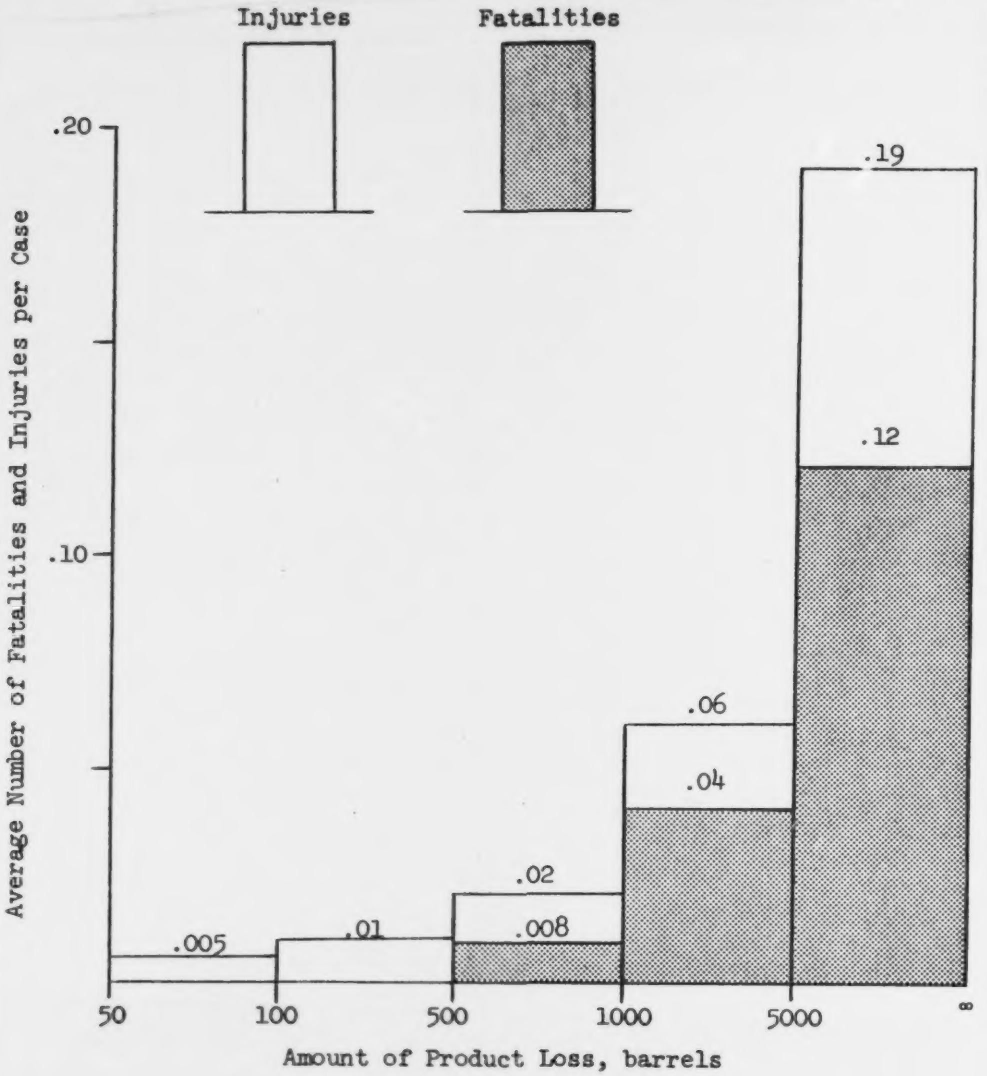


Figure 49. Fatalities and injuries versus amount of product loss in liquid pipeline systems accidents[a].

[a] Reference 58.

frequency and volume of significant spills (typically greater than 50 barrels). Although both the frequency and spill size are important in the evaluation of spills, the product of both parts is typically the most useful in comparing the spill risks of pipeline systems.

In general, a large number of small spills over a period of time is normally expected to result in damage equivalent to one large spill[81]. Based on fatalities alone, however, this equivalence does not apply. Large spills (in excess of 500 barrels) are responsible for most of the fatalities. This is apparent from spill statistics presented in Figure 49.

Evaluation of the measure of relative risk based solely on the mean spill size is useful but somewhat limited. Spills between pumping stations, for example, are expected to occur either as leaks (small to medium spill size) or ruptures (major spill size). Hence, an evaluation of the measure of relative risk based on all three spill sizes (mean, leak, rupture) is essential for a realistic evaluation of spills. It is particularly useful in the development of a practical spill prevention program.

6.2.2.2 Discussion of Risks External to Pipeline System--

Risks external to a pipeline system are also assessed. No industry standards exist for comparing and evaluating the risk of oil spillage after escaping from the pipeline system. Furthermore, an in-depth assessment of this risk is beyond the scope of this study. However, in this study, risks are assessed at a level sufficient for the selection of methods for a spill prevention program. Hence, sources of risks are identified and risk factors assigned (see Section 6.3.2.5). It should be noted that an assessment of the risk external to the pipeline system is extremely important in the selection of optimum methods for a spill prevention program for a particular line.

6.2.3 Applicable Spill Statistics

Available U.S. spill statistics are not ideal, and in many instances are severely deficient regarding the development of spill risks of various pipeline systems. Various government agencies have undertaken to collect and compile spill statistics in order to understand and control the spill problem. However, this information is not oriented towards analyzing and reducing oil spill risks. For example, numerous spills and spill sizes are reportable, but other vital information such as the hole size in the pipe, flow rate, and shutdown time is not reportable. Also, oil spills in certain areas and from certain gathering lines are not reportable. These kinds of limitations and exclusions in spills reportable to U.S. agencies, combined with deficiencies and noncompliance in spill reporting by operating companies (see Section 4.5.2), present limits and constraints on oil spill risk analysis.

Despite these limitations, analysis of available spill statistics indicates that sufficient data are available for developing guidelines for a spill prevention program. Risks, for example, can be established for the major and significant factors affecting oil spillage.

6.2.4 Applicable Information on the Variations of the Complex Pipeline System

The substantial amount of information that exists on U.S. petroleum transportation is not oriented to the details of the various complex pipeline systems. Instead, information deals primarily with demand and supply--quantities imported, produced, transported, etc.

Only a limited amount of information exists that is suitable for comparing individual lines to the U.S. total. Information is available on an individual basis from each company, but there is no industry tool for many of the variations between lines. For example, information is not available on total mileage and age of line pipe for variations such as:

- Depth of burial
- Soil conditions
- Construction
- Materials.

This constraint somewhat restricts the analysis. However, sufficient information is available or can be estimated for the significant variations that are essential for development of guidelines for spill prevention. This is done in Section 6.3 for variations (e.g., line pipe age) of specific pipeline systems and the U.S. total.

6.2.5 Analysis Scheme for the Variations of Pipeline Systems

Risk assessment of the pipeline systems in the U.S. today is complicated by the significant variations between systems. Although these variations can be estimated, they must be accounted for when assessing the risks of oil spills of individual lines or the U.S. total. They also must be accounted for so that an operator can assess the spill potential of his particular line. A number of variations are important such as:

- Age
- Geometry
- Usage
- System shutdown time
- Throughput
- Other.

In order to handle this problem, the following scheme is used in this study. Risks of spills are first established for a typical section of line called a reference line. Then correction factors are established to account for significant differences between the reference pipeline system and most other lines. With this information, the spill risks for most lines can be assessed.

The ability to assess the risks of individual lines is particularly useful for new lines, those in high risk areas, or where a spill problem exists. An assessment capability enables one to determine the need and the extent of a spill prevention program. It also aids in evaluating the practicality and cost-effectiveness of such programs and the locations where implementation may provide the greatest benefits.

6.3 ANALYSIS AND ASSESSMENT OF THE RISK OF ACCIDENTAL SPILLS

This section presents a detailed analysis and assessment of accidental spills. The risk of oil accidentally spilling from a system and the resultant environmental hazards are examined.

The major components of the petroleum pipeline transportation system are first studied in Section 6.3.1. System component(s) with the highest incidence of failure are examined. The risk of spills from line pipe is found to be much greater than from any other petroleum pipeline system components. Correspondingly, the potential for reducing line pipe spills was also found to be much greater. Based on these results, oil spill risks for line pipe were analyzed further.

Risks based on the frequency and volume of spills and their product (relative measure of risk) are examined in Section 6.3.2. These risks are estimated quantitatively for a reference line (a typical section of line). Qualitative estimates are made for the risk of spill damage external to the reference line.

Correction factors that account for significant variations between line pipes are considered in Section 6.3.3. Values are determined for both line variations and the environment external to the line.

By applying these corrections to the reference line, the spill potential for most lines can be estimated. This is done is Section 6.3.4 for the combination of all U.S. lines and a typical pipeline system. Simplified tables and figures are presented to enable a line operator to estimate the spill potential of his own line.

The information from this section is used to estimate oil spillage and cost effectiveness in Sections 6.5 and 6.6. It is also used in Section 7 for the development of guidelines for a spill prevention program.

6.3.1 System Component(s) with the Highest Potential for Frequent and Serious Spill Incidents

The petroleum pipeline transportation system model (see Sections 4.1.3 and 4.2.2) has been divided into the following four major components:

- Production
- Pumping stations
- Line pipe
- Storage facilities.

These components account for all accidental spill incidents. Each major component has been subdivided into a number of main system components (see Figure 4 and Table 7). Each is considered in the evaluation of components with the highest potential for frequent and serious spill incidents.

Spills in petroleum pipeline systems have occurred at most components. This is evidenced, for example, by the spill summary presented in Table 33. However, careful review of the oil spill statistics (such as those presented in Section 4.5.2.1.2) clearly show that most spillage (over 80 percent of the incidents and volume of spills) occurs in line pipe. Of the remaining spills, only two components--tank farms and pumping stations--account for more than two percent of the spill incidents and volume. Tank farm spills typically account for about 13 percent of the spill volume and and only eight percent of the incidents. Most storage tanks are surrounded by dikes to contain accidental spills from tanks. This has significantly reduced petroleum leakage outside the facility and loss of oil (oil can be recovered). The incidence of spills from pumping stations is about eight percent, while the volume spilled is only about three percent of the total. This small spill volume is expected because of the constant vigilance of the operating personnel. This enables almost immediate shutdown of the line or other mitigating measures should a spill occur.

Further reduction of the spill risk of system components other than line pipe appears difficult to attain. Existing U.S. regulations and operating company practices insure effective and frequent inspections of pump stations and tank storage facilities.

Once a line becomes operational, only limited and generally ineffective line pipe inspection and leak detection methods are required by U.S. regulations. These are primarily biweekly visual inspections and inspection and maintenance of cathodic protection systems. Additionally, practices by individual operating companies vary greatly, but methods other than pressure monitoring at pump stations are not generally used. Fortunately, a significant potential for spill reduction does exist because of available leak detection and inspection methods. For example, some companies are using existing continuous monitoring methods (pressure, flow, volume comparison) or developing and implementing advanced methods. These methods are generally useful for identifying large sized breaks or ruptures. Additionally, inspection of line pipe for internal damage or defects is often done and offers great potential for reducing the frequency of spills.

Analysis indicates that implementation of a scheduled maintenance program for line pipe offers the potential for significantly reducing the risk of oil spills. Thus, the main objective and effort in this study is estimating the spill risks and reduction of risks from line pipe by implementing scheduled inspections and/or leak detection.

6.3.2 Oil Spill Risks from a Typical Section of Line Pipe (Reference Line)

Risk values for spills from a typical section of line pipe are established in this section. The following approach is used:

- Typical section of line is defined (assumptions for this reference line are shown in Table 56).
- Failure modes are identified (failure modes are grouped into three main causes of failure: line pipe faults, outside forces and other causes. The advantages of grouping failure modes by cause will be evident in the analysis carried out in later sections that deal with spill prevention. Data for failure analysis are based on the work carried out in Section 4.5.2.1.3).
- Fault tree[14] (see Section 4.2) is constructed based on failure data. (For convenience, symbols used in this fault tree are shown and defined in Figure 50).
- Fault tree is evaluated based on the values of the frequency and mean value of accidental spills.
- Measure of relative risk is evaluated (based on the product of spill frequency and volume for leaks, rupture and average spills).
- Potential severity of the spill or the risk external to the escaping oil is evaluated.

6.3.2.1 Risks--Frequency of Spills F_{ST}--

The expected frequency of spills F_{ST} is the summation of the frequency of spills for each of the individual causes of failures. Individual failures which could result in spill incidents from the typical section of line pipe are identified in the fault tree[a] of Figure 51.

The three main causes of failure are identified in Figure 51. They are:

- Line pipe faults (56 percent spills)
  - Defective pipe (17 percent spills)
  - Corrosion (39 percent spills)
- Outside forces (41 percent spills)
  - Impacts (34 percent spills)
  - Non-Impacts (7 percent spills)
- Other (3 percent spills).

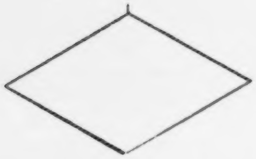
---

[a] Percentages indicated were obtained from Table 19.

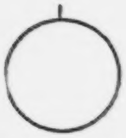
TABLE 56. ASSUMPTIONS FOR TYPICAL SECTION OF LINE PIPE (REFERENCE LINE)

Age:	25 years
Diameter:	10 inches
Length:	1 mile
Commodity:	Crude oil
Flow velocity:	7 feet per second
Flow rate:	2500 barrels per hour
Operating pressure:	1000 psi
Material:	Steel pipe
Construction:	Butt weld joints Buried underground at 3 feet depth
Line elevation:	Horizontal
Corrosion control:	Coated with a cathodic protection system
Pump station shutdown time:	2 minutes
Mainline valve closure time:	72 minutes
External environment:	Low risk - onland - sparsely populated - not near water

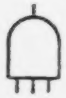
The rectangle identifies an event that results from the combination of fault events through the input logic gate.



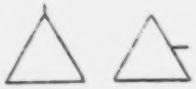
The diamond describes a fault event that is considered basic in a given fault tree. The possible causes of the event are of insufficient consequence or the necessary information is unavailable.



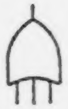
The circle describes a basic fault event that requires no further development. Frequency and mode of failure of items so identified are derived from empirical data.



AND gate describes the logical operation whereby the coexistence of all input events is required to produce the output event.



The triangles are used as transfer symbols. A line from the apex of the triangle indicates a transfer in and a line from the side denotes a transfer out.



OR gate defines the situation whereby the output event will exist if one or more of the input events exists.

Figure 50. Symbolism for fault trees.

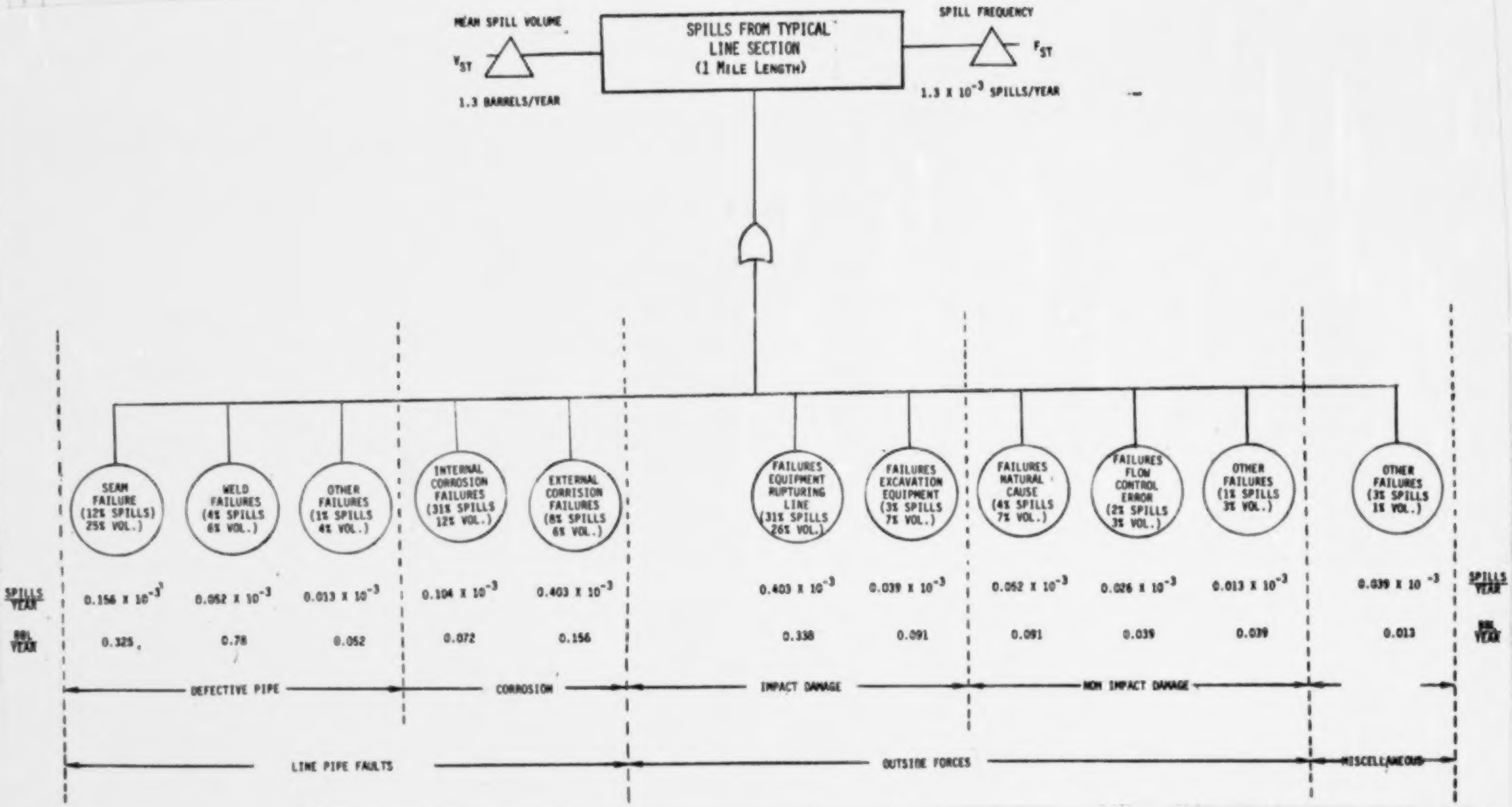

MEAN SPILL VOLUME
V_{ST}
1.3 BARRELS/YEAR
SPILLS FROM TYPICAL LINE SECTION (1 MILE LENGTH)
SPILL FREQUENCY
F_{ST}
1.3 X 10^{-3} SPILLS/YEAR
SEAM FAILURE (12% SPILLS) 25% VOL.)
WELD FAILURES (4% SPILLS 6% VOL.)
OTHER FAILURES (1% SPILLS 4% VOL.)
INTERNAL CORROSION FAILURES (31% SPILLS 12% VOL.)
EXTERNAL CORRISION FAILURES (8% SPILLS 6% VOL.)
FAILURES EQUIPMENT RUPTURING LINE (31% SPILLS 26% VOL.)
FAILURES EXCAVATION EQUIPMENT (3% SPILLS 7% VOL.)
FAILURES NATURAL CAUSE (4% SPILLS 7% VOL.)
FAILURES FLOW CONTROL ERROR (2% SPILLS 3% VOL.)
OTHER FAILURES (1% SPILLS 3% VOL.)
OTHER FAILURES (3% SPILLS 1% VOL.)
SPILLS/YEAR
0.156 X 10^{-3}
0.052 X 10^{-3}
0.013 X 10^{-3}
0.104 X 10^{-3}
0.403 X 10^{-3}
0.403 X 10^{-3}
0.039 X 10^{-3}
0.052 X 10^{-3}
0.026 X 10^{-3}
0.013 X 10^{-3}
0.039 X 10^{-3}
BBL/YEAR
0.325
0.78
0.052
0.072
0.156
0.338
0.091
0.091
0.039
0.039
0.013
DEFECTIVE PIPE
CORROSION
IMPACT DAMAGE
NON IMPACT DAMAGE
LINE PIPE FAULTS
OUTSIDE FORCES
MISCELLANEOUS

Figure 51. Fault trees, V_{ST} and F_{ST}, spill frequency and volume from typical section of line (reference line).

EPA Form 2350-4 (4-80)
(PREVIOUSLY CIR. EPA FORM 287)
TYPING GUIDE SHEET

Line pipe faults such as welds and seam defects and corrosion are responsible for most spills from a typical section of line. These are failures of the line pipe itself and potentially can be reduced by periodic inspections. Outside force incidents, primarily due to impacts, are significant causes of the frequency of spills. These accidents usually involve human error primarily due to insufficient communication between equipment and pipeline operators. Such spills potentially can be reduced by a prevention program that is currently recommended[52] and by leak detection systems that detect impacts on lines before significant damage can occur.

The frequency of spills for the typical section of line pipe (10 inches in diameter and 25 years old) is shown to be approximately 1.30×10^{-3} spills/mile-year, Figure 32. This is in reasonable agreement with both the average (1.34×10^{-3} spills/mile-year) for all line pipe[a], Table 26, and the average (1.15×10^{-3} spills/mile-year) based on the line pipe age, Table 28. Agreement would be expected because the typical line was assumed to be the average diameter and age of line pipe in the U.S. Considering that the U.S. statistics on the actual ages of all U.S. pipelines are not known and mileages were based on estimates, these comparative values are considered quite reasonable.

Data, such as given in Tables 19 and 21, indicate that "leak type" spills (see Section 6.3.3.3) considered here as causing minor to medium damage account for about 75 percent of all reported spills. The frequency of all types of spills for the typical section of line pipe is $1.3\ 10^{-3}$ spills/mile-year. Thus, leaks are estimated to be $0.98\ 10^{-3}$ spills/mile-year. "Rupture type" spills (see Section 6.3.3.3) are considered to account for the remaining 25 percent of the reported spills. Thus, the estimated frequency of spills from ruptures is 0.32×10^{-3} spills/mile-year.

6.3.2.2 Risk--Volume of Spills V_{ST}--

The expected spill volume V_{ST} is the summation of the spill volume for lack of the individual causes of failures. Individual failures which could result in spillage from the typical section of line pipe are identified in the fault tree[b] of Figure 51.

The three main causes of failures are:

- Line pipe faults (53 percent volume)
  - Defective pipe (35 percent volume)
  - Corrosion (18 percent volume)
- Outside forces (46 percent volume)
  - Impacts (33 percent volume)
  - Non-Impacts (13 percent volume)
- Other (1 percent volume).

---

[a] Excluding gathering lines.

[b] Percentages indicated were obtained from Table 19.

TYPING GUIDE SHEET

The total volume spilled from the typical section of line pipe is shown to be approximately 1.3 barrels/mile-year, Figure 33. This result is in agreement with the average volume spilled 1.4 barrels/mile-year for all line pipe (Table 26) and the average volume spilled 1.3 barrels/mile-year based on the average pipeline age (Table 28A).

6.3.2.3 Risks--Size of Spills V_{NLL}, V_{NLR}, V_M--

"Leak type" spills are defined here as those spills that occur as a slow escape of petroleum. These are caused by various line pipe faults and result in hole-through failures ranging from pinhole to medium-sized breaks. These spills are considered to cause small to medium damage (less than 1000 barrels). The nominal[a] largest leak spill size V_{NLL} that could be leaked from the reference line before being noticed and the operation shut down is estimated at 400 barrels. This value, of course, can vary widely depending upon the particular pipeline system. However, the value is realistic considering the limitations of the following two main spill monitoring methods in common use:

- Biweekly or ground patrol visual line inspections for direct indications of leakage. This method, under worst-case conditions, could allow leakage for the entire two-week interval between inspections.
- Pipeline monitoring systems (i.e., pressure monitoring, flow monitoring, etc.) typically can only detect a spill if deviations exceed five percent of throughput.

"Rupture" type spills are defined here as those spills that occur as a sudden escape of petroleum; they are normally caused by various line pipe faults and result in hole-through failures ranging from medium-size breaks to catastrophic failures. These spills are considered to cause medium to major damage. The nominal largest rupture size V_{NLR} for a major pipeline rupture in the typical section of line is estimated to have a maximum spillage of 7500 barrels. This is based on the assumption that a rupture would be detected in about two minutes and about 72 minutes would be required to close a mainline valve.

The mean spill size V_M can be computed from the ratio of V_{ST} and F_{ST}. The computation for the reference line is as follows:

$$V_M = \frac{V_{ST}}{F_{ST}} = \frac{1.3 \text{ barrels/mile-year}}{1.3 \times 10^{-3} \text{ spills/mile-year}} = \frac{1000 \text{ barrels}}{\text{spill}} .$$

---

[a] Based on assumptions as to how the line will operate (e.g., frequency of inspection, accuracy of flow meters, emergency shutdown, etc.), the calculated volume of the pipeline and spill size data for typical lines.

6.3.2.4 Relative Measure of Risks (Frequency x Spill Size) Leak, Rupture, Mean--

The relative measure of risks, product of frequency and spill size, for the typical section of line is shown in Table 57 and Figure 52. Values are provided for both spill frequency and the two largest nominal spill sizes (leak and rupture) and mean size that can be expected from a single accident. This information on leaks and ruptures is particularly important in the evaluation of the potential damage of an accident in a high risk area.

The relative measure of spill risk per year for "leaks" per year is:

$$RMR_{LT} = F_{LT} \times V_{NLL} = \frac{0.98 \text{ spills}}{10^{-3} \text{ mile/year}} \times \frac{400 \text{ barrels}}{\text{spill}} = 0.392 \text{ barrels} \quad .$$

The relative measure of spill risk per year for "ruptures" is:

$$RMR_{RT} = F_{RT} \times V_{NLR} = \frac{0.32}{10^{-3} \text{ mile-year}} \times \frac{7500 \text{ barrels}}{\text{spill}} = 2.4 \text{ barrels} \quad .$$

Since the estimated total of all types of spills for a typical section of line is 1.3 x 10^{-3} spills/mile-year, the relative measure of spill risk per year for all spills is:

$$RMR_{MT} = F_{ST} \times V_{M} = \frac{1.3 \text{ spills}}{10^{-3} \text{ mile/year}} \times \frac{1000 \text{ barrels}}{\text{spill}} = 1.3 \text{ barrels} \quad .$$

6.3.2.5 Risks External to Line Pipe--

The risks (potential severity) external to the line from the accidental spills have been grouped into the following ten categories:

- Fluid transported
- Undergound water supplies
- Water
- Industrial
- Population
- Commercial
- Underground facilities
- Surface transportation
- National preserves
- Spill volume.

TABLE 57. RELATIVE RISK OF OIL SPILLS FROM A TYPICAL SECTION OF LINE PIPE

Type of Spill	Frequency (Per Year)	Spill Size	Nominal Largest Size (Barrels)	Risk (Barrels/Year)
Leak	0.98×10^{-3} (F_{LT})	Small to Medium	400 (V_{NLL})	0.392 (RMR_{LT})
Rupture	0.32×10^{-3} (F_{RT})	Medium to Major	7500 (V_{NLR})	2.4 (RMR_{RT})
Mean	1.3×10^{-3} (F_{ST})	Medium to Major	1000 (V_M)	1.3 $(V_{ST}), (RMR_{MT})$

Note: V_M (Mean spill size) = V_{ST}/F_{ST}

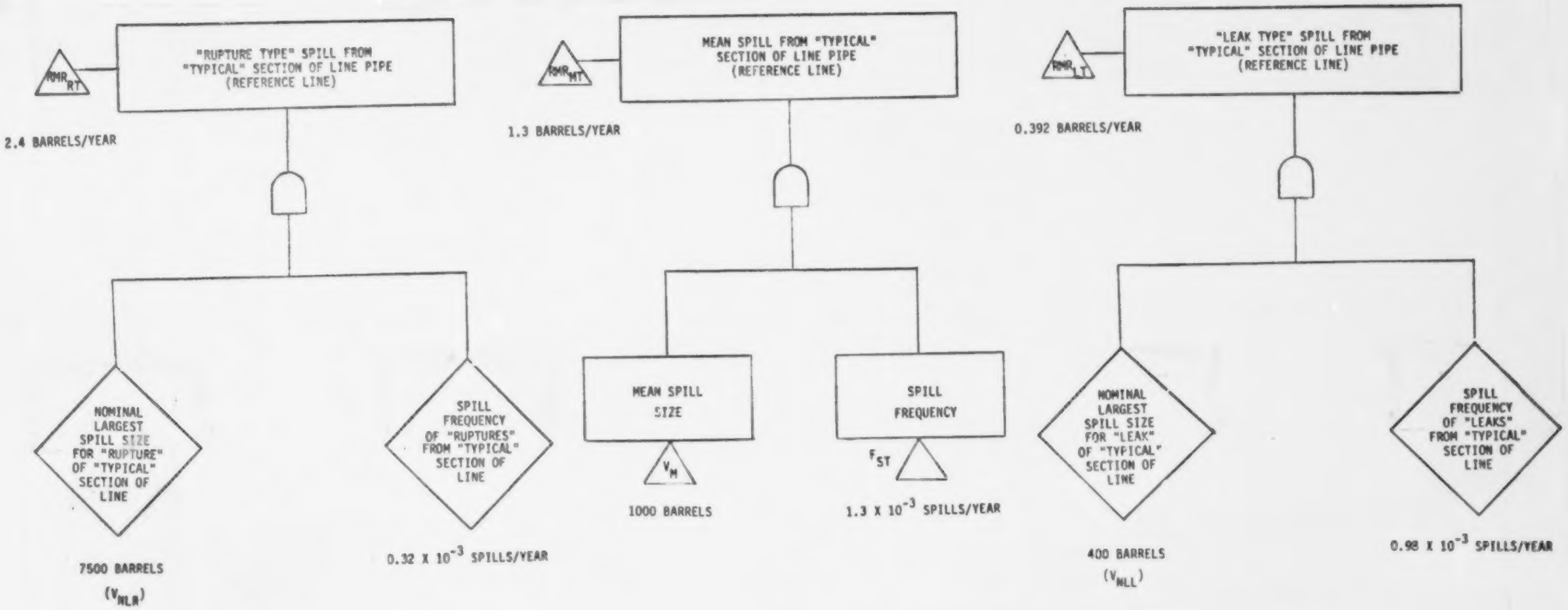

"RUPTURE TYPE" SPILL FROM "TYPICAL" SECTION OF LINE PIPE (REFERENCE LINE)
RMR RT
2.4 BARRELS/YEAR
NOMINAL LARGEST SPILL SIZE FOR "RUPTURE" OF "TYPICAL" SECTION OF LINE
7500 BARRELS
(V NLR)
SPILL FREQUENCY OF "RUPTURES" FROM "TYPICAL" SECTION OF LINE
0.32 X 10-3 SPILLS/YEAR
MEAN SPILL FROM "TYPICAL" SECTION OF LINE PIPE (REFERENCE LINE)
RMR MT
1.3 BARRELS/YEAR
MEAN SPILL SIZE
V M
1000 BARRELS
SPILL FREQUENCY
F ST
1.3 X 10-3 SPILLS/YEAR
"LEAK TYPE" SPILL FROM "TYPICAL" SECTION OF LINE PIPE (REFERENCE LINE)
RMR LT
0.392 BARRELS/YEAR
NOMINAL LARGEST SPILL SIZE FOR "LEAK" OF "TYPICAL" SECTION OF LINE
400 BARRELS
(V NLL)
SPILL FREQUENCY OF "LEAKS" FROM "TYPICAL" SECTION OF LINE
0.98 X 10-3 SPILLS/YEAR

Figure 52. Relative measure of risk of oil spilled from typical section of line (reference line)--leaks, ruptures, mean.

The relationship of these potential failures is shown in the fault tree of Figure 53. It should be noted that the risk value for failures in each category is assigned a value of one because the typical line is assumed to be located in a low-risk area. Correction factors that account for a complete range of risks (i.e., low, medium, high), are provided in Section 6.3.3.4.

6.3.3 Correction Factors--General Use

The spill potential of most lines may be estimated by applying correction factors[a] to the values developed for the reference line[b]. These factors correct for the significant variations (e.g., geometry, age, etc.) between lines. They are intended to provide a simple and practical means of accounting for the overall effect of these variations on line pipe failures.

Correction factors are provided for variations that have significant effects on the four main items that are used in evaluating the risks of oil spills. These are:

- Frequency of spills
- Volume of spills
- Size of spills
  - Mean
  - Leak
  - Rupture
- External environment.

The first three items are primarily related to failures of the line itself. The fourth item deals with damage to the environment, external to the line pipe, that occurs after or during an accidental spill of petroleum. Correction factors for each of these four items are provided in the subsections that follow.

---

[a] Because reportable information on accidental spills and operating company lines in the U.S. is limited (see Section 6.2.1), values for some factors may be qualitative and should be considered as very rough estimates. These factors are intended for use in developing spill prevention and control guidelines and should not be used for other analysis purposes.

[b] In this section it is assumed that the lines commonly use similar inspection and leak detection methods (see Section 6.3.1). Thus, correction factors are not included for these methods.

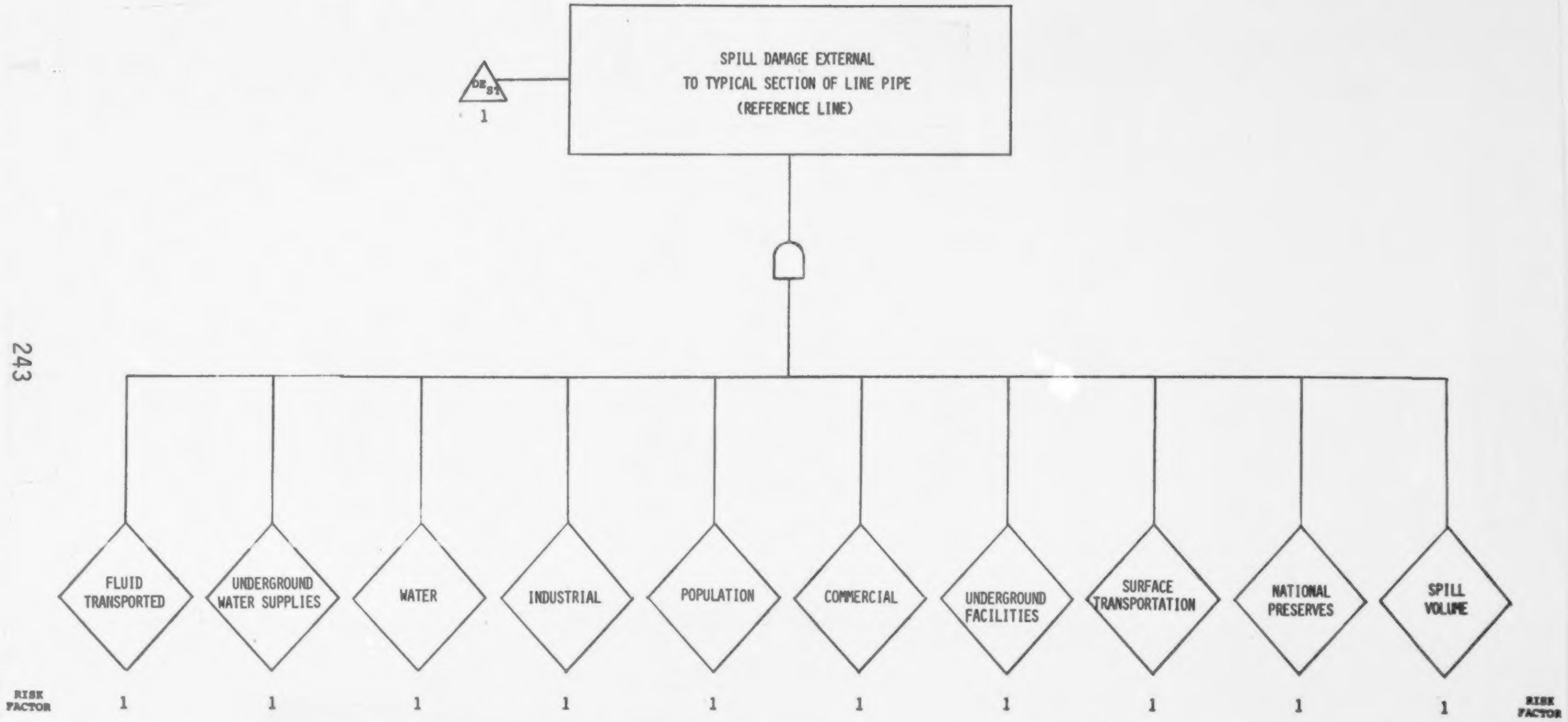

SPILL DAMAGE EXTERNAL TO TYPICAL SECTION OF LINE PIPE (REFERENCE LINE)
DE_{ST}
1
FLUID TRANSPORTED
UNDERGROUND WATER SUPPLIES
WATER
INDUSTRIAL
POPULATION
COMMERCIAL
UNDERGROUND FACILITIES
SURFACE TRANSPORTATION
NATIONAL PRESERVES
SPILL VOLUME
RISK FACTOR
1
1
1
1
1
1
1
1
1
1
RISK FACTOR

Figure 53. Fault tree, DE_{ST}, spill damage external to typical section of line pipe (reference line).

6.3.3.1 Frequency of Spills--

Many factors influence the frequency of spills from line pipes transporting petroleum. Analysis and evaluation of available spill data indicate, however, that only a few factors vary in such a manner as to significantly affect the incidence of spills between different lines. These include:

- Age
- Geometry (diameter, wall thickness)
- Use
- Length.

Another important consideration is the minimum spill size. In this analysis, spills of 50 barrels or more generally are considered to be significant. In certain high-risk areas, however, even a spill of a few barrels might be considered significant. Thus a correction factor is included for spills between 1 and 50 barrels. Values for correction factors are provided for each of these five items in Figure 54. A fault tree for these correction factors is shown in Figure 55. Note that the overall correction factor, CF_F, is the product of the individual correction factors. The five items are treated separately in the subsections that follow.

Other factors that are important include:

- Depth of burial
- Type of line
- Corrosion control
- Construction
- Material
- Soil condition
- Operating pressures
- Maintenance and inspection
- Overpressure.

The effect of this latter group appears to be minor. Effects of many of these items are partially accounted for by the former group. For example, the quality of line pipe construction and materials decreases with age. Information that is necessary for a very accurate estimate of the effect of these items in this latter group is not generally available (i.e., reportable to government agencies or available in the literature). For example, the number of accidents versus depth of cover is reported, but the miles of pipeline for each depth are unknown. The same holds true for type of weld and grade of pipe. Despite the lack of optimum information, reasonable estimates can be made of the effects of these factors. Information pertaining to the actual spills is reportable (e.g., Appendices A and B), and reasonable estimates of the relative effect of these factors are possible.

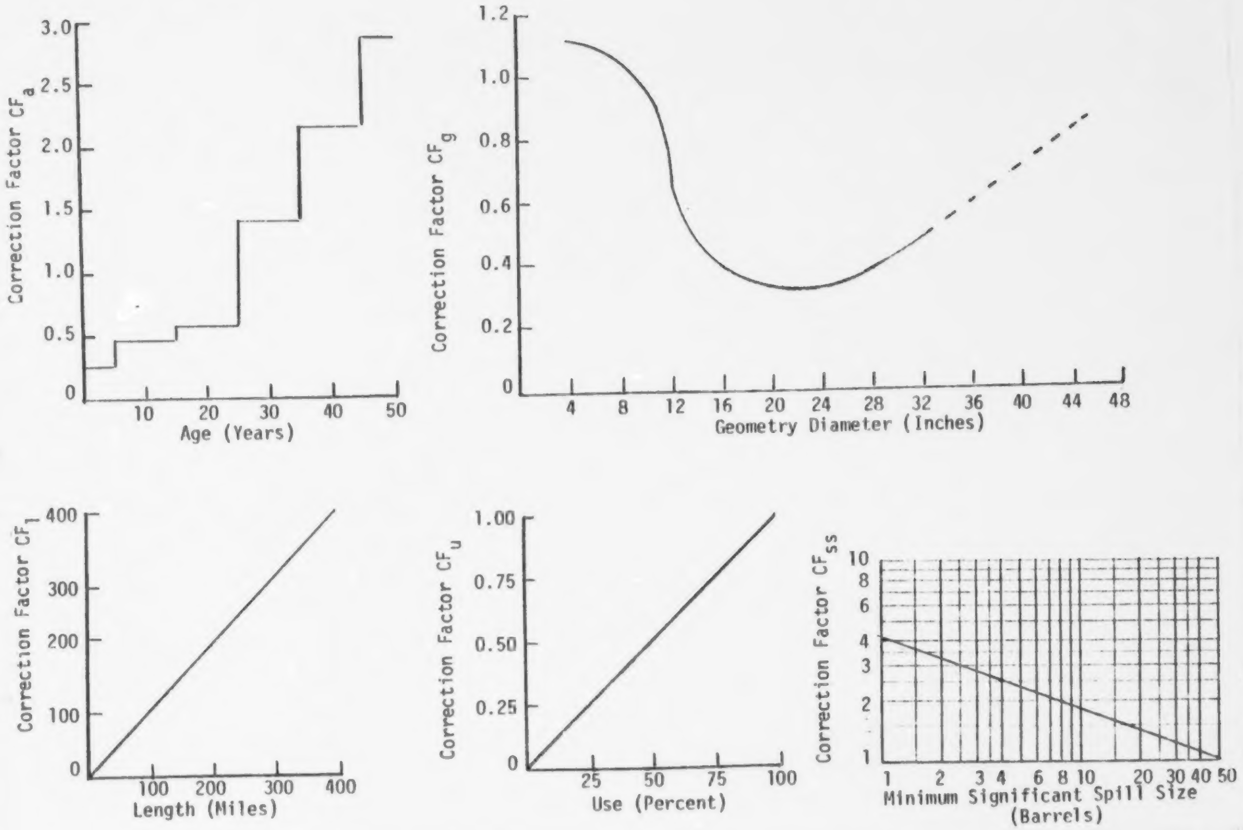


Figure 54. Correction factors for frequency of spills--age, geometry, length, use, size.

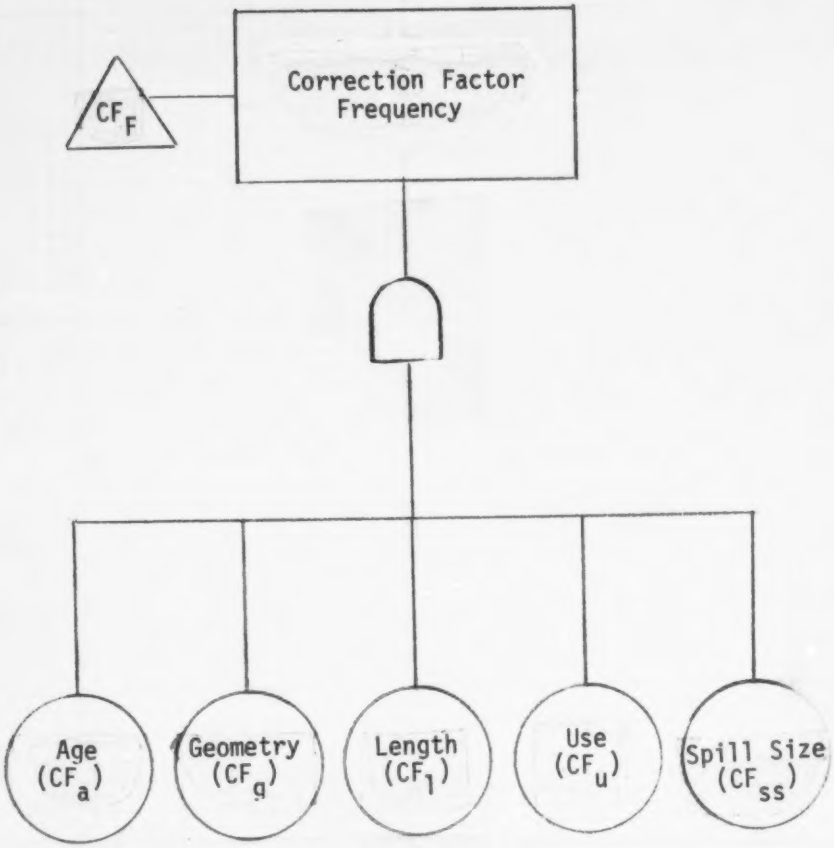

CF_F
Correction Factor Frequency
Age (CF_a)
Geometry (CF_g)
Length (CF_l)
Use (CF_u)
Spill Size (CF_ss)

Figure 55. Fault tree, CF_F, correction factors for frequency of spills.

Additionally, important statistics required for analysis such as mileage of line pipe by age can be estimated, and mileage of line pipe for each diameter and location (state) is known.

6.3.3.1.1 Age

Corrections for line pipe age are provided in Figure 53. Results indicate that the age of the line pipe has the most significant effect on the estimated spill frequency.

Data such as presented in Figure 36 and Table 28A show a dramatic increase in the spill frequency with pipe age. Results presented in Figure 36A and Table 25 clearly show that the age of the line pipe is a major factor in the frequency of incidents. Lines built before 1950 appear to have a much greater incidence of corrosion, while lines built before 1930 appear to have a much greater incidence of spills caused by outside forces.

Corrosion is a time-dependent process. Hence, older lines are expected to have a higher incidence of corrosion. Also, as the average age of U.S. lines continues to increase, higher incidents of corrosion normally would be expected. However, spills reportedly caused by corrosion have decreased significantly in the past few years. Some of this decrease can be accounted for by operator compliance with U.S. regulations that are intended to reduce line pipe corrosion (i.e., Titles 49, Part 195.414, 195.415, and 195.416). Other decreases can be attributed to operator systems that exceed the requirements of government regulations.

6.3.3.1.2 Geometry-Diameter and Wall Thickness

Corrections for line pipe geometry (CF_g) are provided in Figure 54. These corrections indicate that the diameter of the line pipe has the second most significant effect on the frequency of spills.

Data presented in Figure 32 show that the incidence of spills decreased rapidly with increasing line pipe diameter. This result occurred for line pipe diameters of four inches to approximately 16 inches. The incidence of spills increased slightly for line pipe diameters of 16 inches to 32 inches. These results are in almost direct contrast to the expected incidence of spills based purely on the cross-sectional area of the pipe; spill frequency normally would be expected to increase with increasing cross-sectional area of the pipe.

There are a number of possible explanations to account for these contrasting results. Recent research[82] on line pipe damage has indicated that thin-wall line pipe is more easily damaged. Our analysis of spill data indicates that this conclusion is reasonably correct for pipelines transporting liquids. Thin-walled small-diameter lines, particularly older ones (built before 1934), have a higher frequency of failures from outside force incidents. Data indicates that the wall thickness effect appears to become less a factor for line pipe diameters greater than 16 inches. At about this diameter, defective pipe and corrosion cause increasingly more failures apparently because of the larger cross-sectional areas.

The age of the line pipe for each diameter is not known and the effects of age are uncertain. However, larger diameter lines (i.e., greater than 16 inches in diameter) would be of newer vintage. Thus, low rates of failure from corrosion and construction defects would be expected. Also, the mileage of line pipe by diameter that is excluded from reporting (primarily gathering lines) is unknown. Despite the limited data available, the correction presented in Figure 54 is considered to provide an adequate estimate of the overall effects of the various causes of line pipe failures as related to diameter.

6.3.3.1.3 Use

Corrections for line pipe use (CF_u) are provided in Figure 54. The frequency of spills is assumed to be directly related to the use of the line. For example, if the line is in operation 50 percent of the time, the incidence of spills would be expected to be slightly more than 50 percent of the value than if the line were operating at all times. Long periods of shutdown would be expected to increase the frequency of spills, for example, from internal corrosion.

6.3.3.1.4 Length

Corrections for line pipe length (CF_l) are provided in Figure 53. The frequency of spills is assumed to be directly related to the length of the line. For example, if a line is 100 miles long, the incidence of spills would be expected to be 100 times greater than the one-mile section of line.

6.3.3.1.5 Minimum Spill Size

The correction factor for the frequency of spills for spill size (CF_{SS}) of less than 50 barrels is shown in Figure 54. Various data and other considerations were evaluated for this correction factor.

Spills of less than 50 barrels are difficult to estimate. Most spills of less than 50 barrels are not reportable. Estimates of spills of less than 50 barrels that are reported are also subject to criticism. Various data bases (U.S. and foreign) on accidental spills are available for estimating these incidents. For example, the mathematical analysis in Appendix E, based on OPSO reported spills, indicates that at least 70 percent of crude spills are less than 50 barrels. Data in Table 33 indicate that this percentage is much lower. In contrast, careful reporting and analysis of spills by one company, for a number of lines and for a large amount of throughput, indicates that over 85 percent of the spills were less than 50 barrels. Other data bases such as Figure 42, indicate similar varying results.

The size of small spills in the range of 50 barrels is especially difficult to estimate accurately for a number of reasons. No specific guidelines are in common use for accurately estimating the spill size. One would normally expect a natural tendency to underestimate the size of a small spill and thus many spills may go unreported.

Taking all these items into consideration, the correction factor for minimum spill size is given in Table 54. This factor is based on the assumptions that 75 percent of the spills are less than 50 barrels and the size distribution is similar to the one presented in Figure 42.

6.3.3.1.6 Other Important Factors

Depth of Cover

The number of outside force incidents has been reported as a function of the depth of burial of line pipe (Table 31), but the mileage, geometry, and age of line at each depth are not reported. Thus, the effect of depth of cover on the incidence of spills cannot be properly evaluated and a correction factor developed. Depth of cover is considered an important factor in the incidence of spills, and suitable information is needed for proper evaluation.

It should be noted that only 21.1 percent of the incidents occured for a depth of cover from 31 to 40 inches (Table 31). Assuming[a] a much larger proportion of lines are under this depth of cover than the portion of incidents reported, it could be inferred that a suitable depth of cover is a significant factor in reducing the spill frequency.

The depth of cover for underwater lines is an extremely important factor in preventing spills. This is because most accidents from outside forces are due to external impacts from such sources as anchor dragging. A depth of cover of three to four feet is normally sufficient to eliminate most damage from anchor dragging. In the case of onland lines, equipment rupturing lines is the predominant cause of damage by outside forces and evacuation equipment a minor one. A depth of cover of three to four feet is considered sufficient to minimize spills caused by most equipment.

Depth of cover often becomes a problem because of soil erosion. For example, lines buried underwater at three feet may become uncovered due to ocean currents or onland lines due to erosion from water. Thus, even if a line is buried, it is considered important to inspect the depth of cover. This is particularly important for underwater lines where impact damage cannot be easily detected. It may also be significant for onland lines, particularly in high risk areas, because of potential damage from equipment rupturing the line.

The depth of cover as required by existing U.S. regulations is considered adequate for line pipe. The possibility exists that the cover above the line may substantially decrease, and in some instances the line may become exposed because of soil erosion or other events. This is considered to be a factor in the incidence of spills. However, there is insufficient information pertaining to the depth of cover to establish a suitable risk-correction factor. But this problem will be considered in the development of a spill prevention program.

---

[a] In 1971 and 1974, for example, there were 67 and 76 cases of equipment rupturing the line and only four and eight cases of spills caused by excavation.

Various other factors have some bearing, but do not appear to be major factors in the frequency of spills. A brief discussion of a few of these follows.

Type of Line

Crude gathering and trunk lines cannot be distinguished for most of the incidents of spills reported to OPSO. Also, a large portion of the gathering lines are exempt from spill reporting. Thus, a truly accurate correction factor cannot be developed. However, crude and product trunklines appear to have similar incidence of spills. This is indicated in Figure 26 where crude spills averaged about 0.88 spills per mile, while product spills average 0.92 spills per mile. Product lines are generally newer and of larger diameter than crude lines; thus, a lower spill rate would be expected for product lines. This latter observation is found to be correct when most crude gathering lines are not included in the total mileage used in computing spills per mile. For this exclusion, crude spills average 1.3 spills per mile. Crude lines are slightly older and of smaller diameter. However, age and geometry effects have already been accounted for.

Based on these considerations, there appear to be no significant differences for the type of line. Thus, no correction factors are provided.

Corrosion Inspection and Control

U.S. regulations exist for installation, maintenance and periodic inspection of cathodic protection systems and for corrosion control (see DOT 49 CFR 195.414, DOT 49 CFR 195.416 and DOT 49 CFR 195.418). These regulations apply to most lines and are primarily for reduction of external corrosion. Since these regulations are quite comprehensive and are applied equally to most lines, there appears to be no need for correction factors.

6.3.3.2 Volume of Spills--

A variety of factors influence the volume of spills from line pipe transporting petroleum. However, only a few of the variations between lines are considered to have the potential of significantly affecting the spill volume. These include:

- Diameter
- Length
- Use
- Pumping station shutdown time
- Mainline valve closure time
- Line elevation.

A fault tree for these correction factors is shown in Figure 56. The overall correction factor CF_{SV} is the product of the individual correction factors. Values for correction factors are presented in Figure 57 for diameter, length, use and pumping station shutdown. Correction factors are not provided for mainline valve closure time and line elevation but these can be computed using information provided in Table 48 and Reference 58 (see also Section 6.3.1). These are considered to be less significant than the first four factors. Estimates for these latter two factors are difficult to make for two reasons. First, a number of variables must be considered. Secondly, necessary information for many of these variables is either not available or unknown.

6.3.3.2.1 Diameter

Corrections for the diameter of the line pipe (CF_d) are provided in Figure 37. Results indicate that the diameter of the line has a major effect on the estimated volume of a spill.

Data, such as presented in Table 26 and Figures 31 and 33, show a dramatic increase in the average spill size with pipe diameter. The spill size is essentially proportional to the cross-sectional area of the pipe. These data follow approximately the same profile as the spill size data for Western Europe and Canada (Figure 41). However, the mean spill size in the U.S. for each diameter appears to be much larger than for Western Europe, i.e., 1000 barrels to 666 barrels.

6.3.3.2.2 Length

Corrections for line pipe length (CF_l) are provided in Figure 57. The volume of spills is assumed to be directly related to the length of the line. For example, if a line is 100 miles long, the volume of spills would be expected to be 100 times greater than the one-mile section of line.

6.3.3.2.3 Use

Corrections for line pipe use (CF_u) are provided in Figure 57. The volume of spills is assumed to be directly related to the use of the line.

6.3.3.2.4 Pumping Station Shutdown

Corrections for pumping station shutdown time (CF_{PS}) are presented in Figure 57. This correction is an important consideration in the volume of accidental spills. In the event a rupture or large-size break occurs, the ability to rapidly shut[a] the system down at the pumping stations is

---

[a] Shutdowns not occurring at the proper time should be avoided. Incorrect shutdown can create surge pressure that might cause leaks at other line pipe locations.

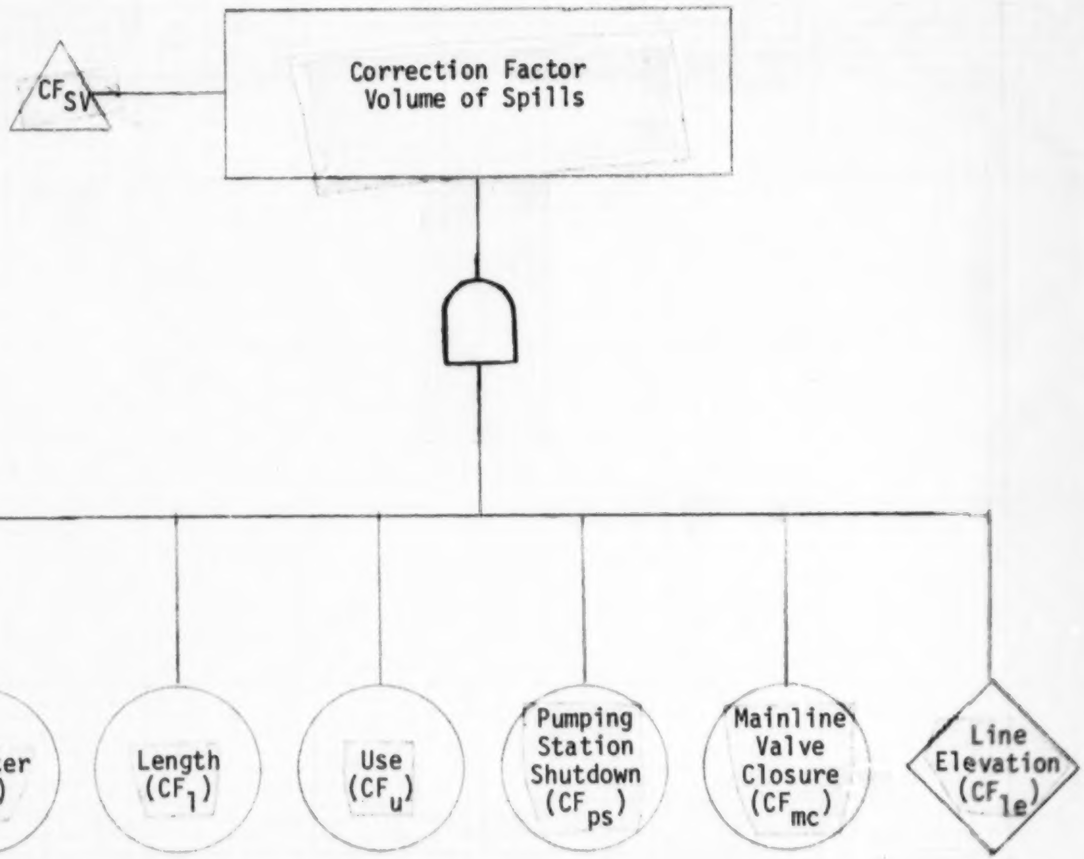

CF_{SV}
Correction Factor Volume of Spills
Diameter (CF_d)
Length (CF_1)
Use (CF_u)
Pumping Station Shutdown (CF_{ps})
Mainline Valve Closure (CF_{mc})
Line Elevation (CF_{le})

Figure 56. Fault tree, CF_{SV}, correction factor for the volume of spills.

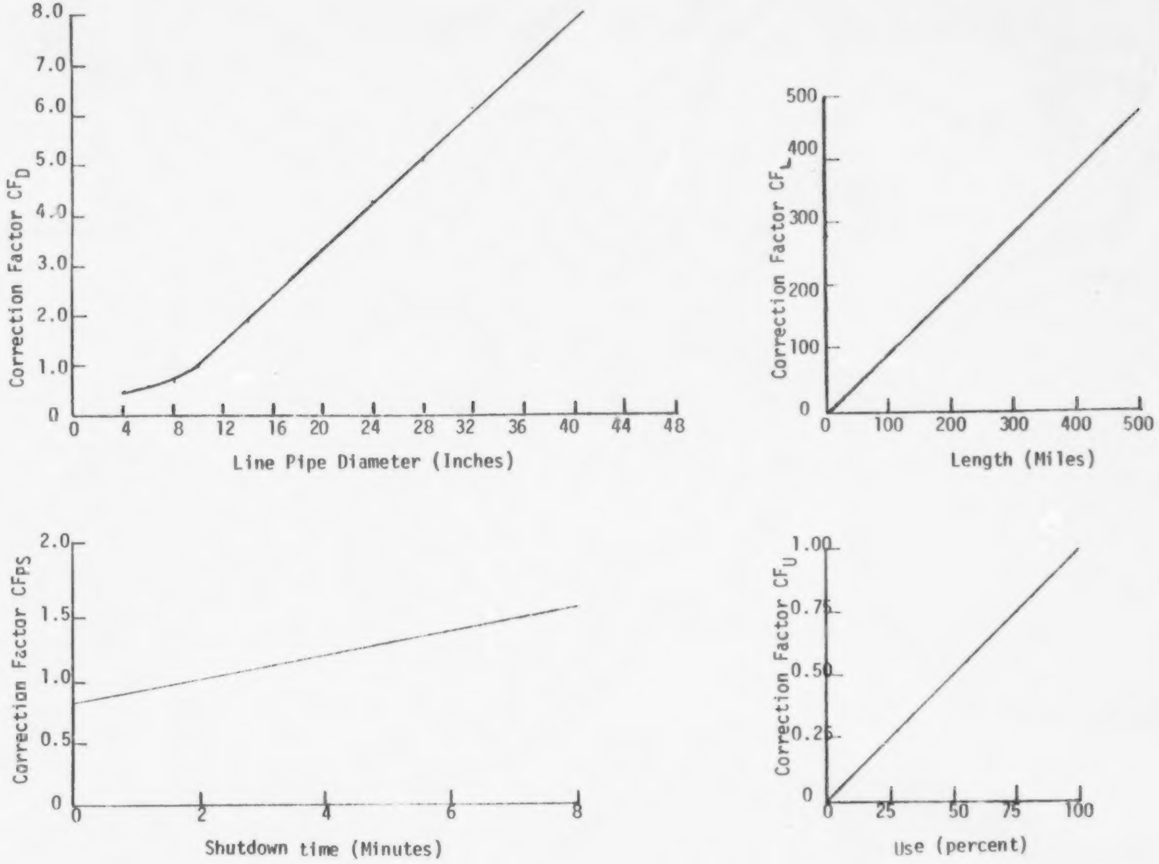


Figure 57. Correction factors for volume of spills--diameter, length, use, shutdown time.

critical in minimizing the volume spilled. For example, if a line rupture discharge rate[a] were 5,000 barrels per hour, a two-minute pump shutdown time would allow 166 barrels to be spilled, a six-minute shutdown time would allow 500 barrels to be spilled.

A survey of pumping station facilities indicates that over 50 percent of the facilities can shut their systems down within one minute, 70 percent in two minutes, 96 percent in five minutes. Thus, a range of zero to five minutes was used in the correction factor. Also, it was assumed for the reference line that rupture-type spills would be detected within ten minutes and the line required two minutes for pump shutdown. Thus, if it required five minutes to shut the pumps down in another line, the spill volume for this line would be expected to be at least 25 percent greater than for the reference line.

6.3.3.2.5 Mainline Valve Closure

Rapid closure of a mainline valve can significantly reduce the volume of petroleum that escapes from an accidental spill. A recent study[58] indicates that additional spillage can occur unless the mainline valves are closed rapidly after pump station shutdown. This study indicates, for example, that a 14-inch line with a break (4-inch diameter hole) at the bottom could decrease the 300 barrels per hour of spillage after pump station shutdown. However, diffusion into the surrounding soil and eventual buildup around the pipe until the static head is equalized is expected to significantly reduce the spill rate.

Results of an industry survey[58] indicated that it requires an average of 72 minutes to reach and close a mainline valve and an average of 2.6 minutes for a remotely controlled valve. Ninety-five percent of the valves surveyed required manual closure. Manual closure and a 72-minute closure time was assumed for the reference line.

In addition to the effect of fluid buildup, a number of other factors affect the spill rate. These include:

- Hole size
- Location of hole
- Line pressure
- Line elevation
- Soil
- Other.

Again, the effect of many of these factors on the spill rate is unknown. Thus, an accurate estimate of this factor is difficult for individual lines. It is extremely complicated to develop a general factor that could apply to most lines. Considering that the effect of mainline valve closure is of much less significance than CF_d or CF_{ps} and considering also the difficulty in obtaining an accurate correction factor for CF_{mvc}, a value of one is normally assumed for this correction factor.

---

[a] Line pipe rupture can result in spills in excess of throughput. Depending upon the line, spill rates can exceed flow rates by large factors (i.e., two or three).

6.3.3.2.6 Line Elevation

Even after pumping station shutdown and mainline valve closure, spillage can occur because of the existing static head in an elevated line. This problem is particularly significant in isolated and/or high risk areas. The extent of the effect of line elevation depends upon a number of line parameters (e.g., diameter, pressure, flow rate, etc.) and is not simply determined. Values for the line elevation correction factor (CF_{le}) are not provided here (assume unity) but should be estimated for a particular line where a potential problem exists. The relationship of line elevation to other correction factors, however, is shown in the fault tree (Figure 56).

6.3.3.2.7 Other Factors

Flow Velocity

Flow velocities depend upon the size of the line and typically range from 6 fps for six-inch lines to 12 fps for 36-inch lines. No correction factor is provided since the factor is accounted for in the line diameter correction.

Location of Mainline Valves

Check valves in uphill sections and remotely controlled valves in downhill sections are desirable. Since 1974, the ANSIB 31.4 Code requires remotely-controlled valves at a maximum spacing of 7.5 miles in commercial, residential and industrial areas and 10-mile spacing of manual valves for other liquids.

Valves generally cannot be installed in long length offshore lines. This presents a serious problem in underwater lines located in elevated areas.

6.3.3.3 Size of Spills--

Most of the factors that have a significant influence on the volume of spills also influence the size of spills. These include:

- Diameter
- Pumping station shutdown time
- Mainline valve closure time
- Line elevation.

These four factors have an effect on the size of spills resulting from ruptures or mean (average size) spill size. Fault trees for ruptures CF_{VR} and mean size spills CV_{VM} are presented in Figure 58. Values for these correction factors are the same as those presented for the volume of spills in Table 57. Also, the discussion of each factor presented in Sections 6.3.3.2.1 through 6.3.3.2.4 applies to the size of spills and will not be repeated here.

All four factors are considered to have a very minor effect on the spill size for leaks. Thus, no correction factors of fault tree are provided for "leak type" spills.

6.3.3.4 External Environment--

There are many risks to the environment from escaping petroleum. These risks are identified for each of ten categories in Table 58. Correction factors that account for a complete range of risks (low, medium, high) are also presented in this table. Many of the values[a] for the correction factors are considered to be only qualitative estimates (see Section 6.2.1) because of the absence in required spill reporting forms of suitable quantitative data relating to the external environment.

A fault tree for correction factors for risks to the external environment from escaping petroleum is presented in Figure 59. Note that the overall correction factor, CF_{ED}, is the product of the individual correction factors.

Rather than discuss each correction factor value in each category, examples of typical categories will be provided. Spills occurring in lakes and rivers generally can be confined to small areas using suitable containment techniques; risk factors of 10 and 20 are assigned, respectively. Offshore spills, however, are quite difficult to contain and often (about 95 percent of the time) reach recreational areas along the shoreline; risk factor of 100 is assigned for spills located offshore. A recent study[46] indicates that a serious potential exists for damage to underground water supplies in the United States. The study indicates that large supplies near large urban populations are particularly vulnerable. Based on information contained in the study, lines near medium to large volumes of underground water supplies are assigned risk factors of 10 and 100, respectively.

6.3.4 Computation of Oil Spill Risk for Accidental Spillage

6.3.4.1 Risks that Oil will Escape from the Line Pipe--

Oil spill risks for line pipe for most petroleum pipeline systems can be computed using information supplied in this section. Values are obtained by applying the appropriate correction factors to the values determined for the reference line.

---

[a] These values are primarily intended to identify sources of high risk and for use in developing guidelines in this study. They should not be used in other analyses.

BEGIN FIRST LINE OF TEXT HERE
CENTER OF PAGE
TOP OF IMAGE AREA
DROPPED HEAD. BEGIN SECTIONS HERE

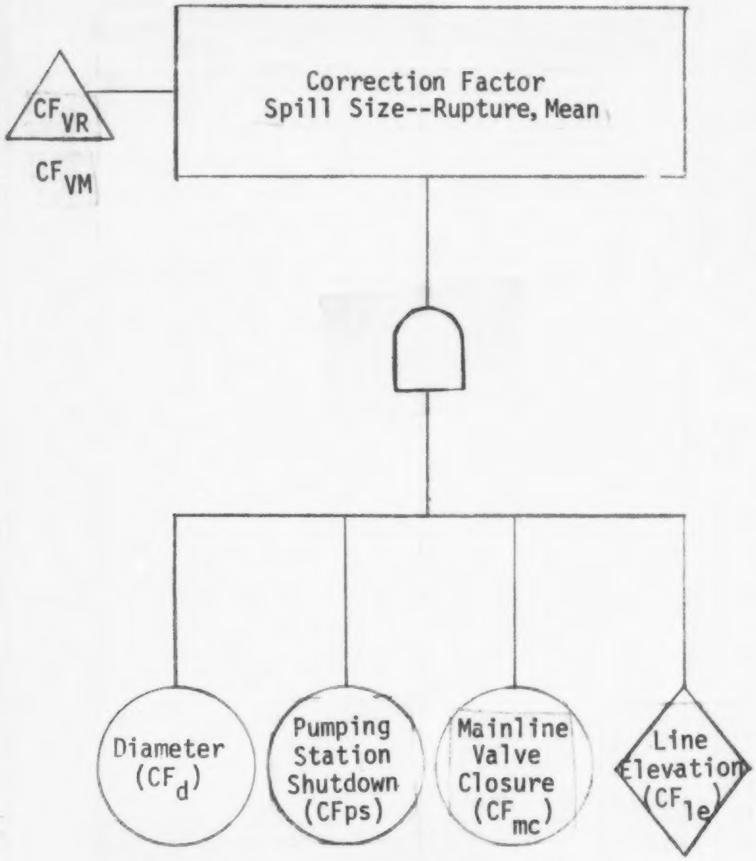

Correction Factor
Spill Size--Rupture, Mean
CF_VR
CF_VM
Diameter (CF_d)
Pumping Station Shutdown (CFps)
Mainline Valve Closure (CF_mc)
Line Elevation (CF_le)

Figure 58. Fault tree, CF_{VR} or CF_{VM}, correction factors for spill size--rupture and mean.

BEGIN LAST LINE OF TEXT
BOTTOM OF IMAGE AREA OUTSIDE DIMENSION FOR TABLES AND ILLUSTRATIONS
PAGE NUMBER
EPA Form 2350-4 (4-80)
(PREVIOUSLY 23H, EPA FORM (3))
TYPING GUIDE SHEET

TABLE 58. CORRECTION FACTORS FOR RISK OF SPILL DAMAGE EXTERNAL TO LINE PIPE

Location or Commodity	Correction Factor Identification	Low Risk 1-4	Medium Risk 5-9	Major Risk 10-100
1. Fluid Transported	CF_{ft}			
Crude		1(1)		
Products				
LPG		3		
LNG				10
Other		2		
2. Underground Water Supplies	CF_{uw}			
Zero potential		1(1)		
Small volume		1		
Medium volume			10	
Large volume				100
3. Water	CF_{w}			
Zero potential		1(1)		
Stream		2		
Lake				10
River				20
Marshlands				100
Offshore				
Beaches				100
Terminals				100
High seas				100
4. Industrial	CF_{i}			
Zero		1(1)		
Light		2		
Medium			5	
Heavy				10
5. Population	CF_{p}			
Undeveloped		1(1)		
Rural		1		
Residential			10	
Urban				100
6. Commercial	CF_{c}			
Zero		1(1)		
Light			5	
Medium				10
Heavy				50
7. Underground or Adjacent Facilities	CF_{uf}			
Zero		1(1)		
Electrical		2		
Gas			5	
LPG				10
LNG				100
8. Surface Transportation	CF_{st}			
None		1(1)		
Road		1		
Highway			5	
Railway				10
Freeway				20
Major freeway				50
9. National Preserve	CF_{np}			
Zero		1(1)		
Small			5	
Medium				10
Major				50
10. Spill Volume	CF_{sv}			
Fatalities				
1-100 (barrels)		1		
100-500 (barrels)		1(1)		
500-1,000 (barrels)		2		
1,000-10,000 (barrels)			5	
>10,000 (barrels)				10
Injuries				
0-100 (barrels)		1		
100-500 (barrels)		1(1)		
500-1,000 (barrels)		2		
1,000-10,000 (barrels)			5	
>10,000 (barrels)				10

Note: (1) Reference Line Pipe

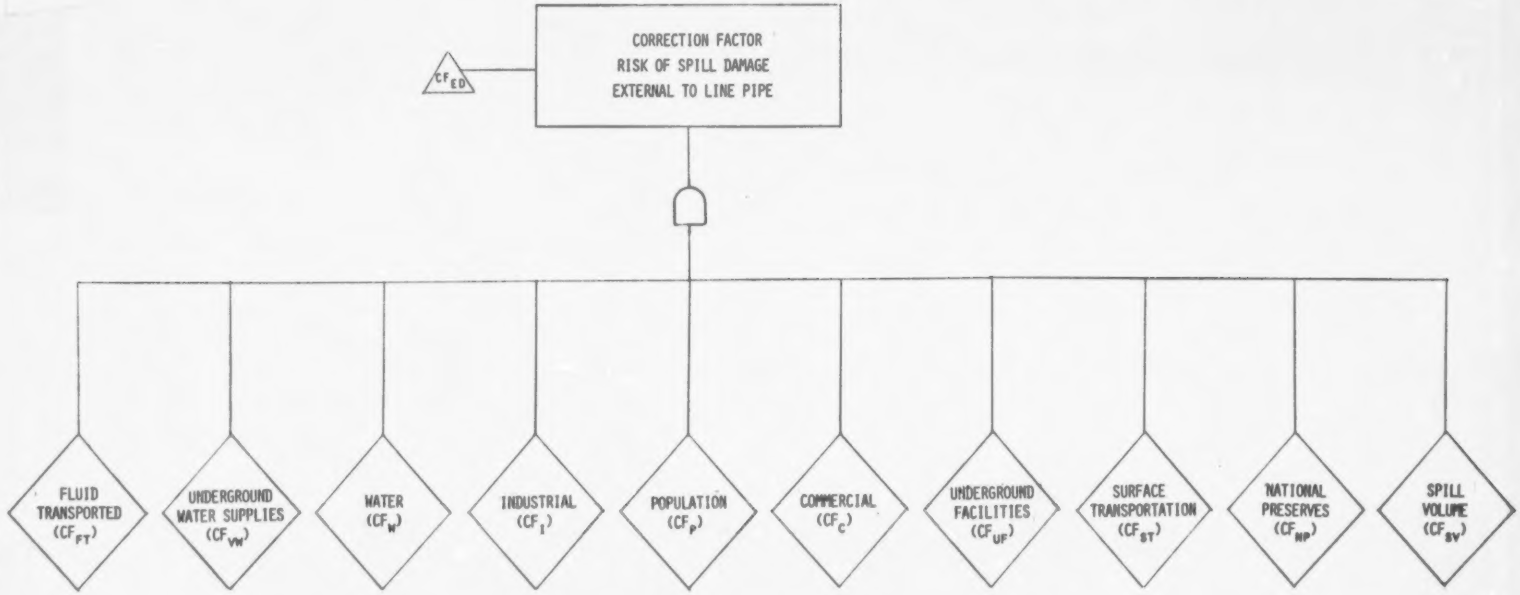

CORRECTION FACTOR
RISK OF SPILL DAMAGE
EXTERNAL TO LINE PIPE
CF_{ED}
FLUID TRANSPORTED (CF_{FT})
UNDERGROUND WATER SUPPLIES (CF_{VW})
WATER (CF_W)
INDUSTRIAL (CF_I)
POPULATION (CF_P)
COMMERCIAL (CF_C)
UNDERGROUND FACILITIES (CF_{UF})
SURFACE TRANSPORTATION (CF_{ST})
NATIONAL PRESERVES (CF_{NP})
SPILL VOLUME (CF_{SV})

Figure 59. Fault tree, CF_{ED}, correction factors for risks of spill damage external to line pipe.

Oil spill risks for frequency F_{STC} and volume V_{STC} of spills can be computed using Table 59 and the figures indicated. Fault trees for F_{STC} and V_{STC} are shown in Figure 60.

Oil spill risks of the nominal largest spill size of ruptures V_{NLRC}, leaks V_{NLLC} and mean volume V_{MC} can be computed using Table 60 and the indicated figures. Fault trees for V_{NLRC}, V_{NLLC} and V_{MC} are shown in Figure 61.

The relative measure of oil spill risks for rupture RMR_R, leaks RMR_L and means spills RMR_M can be computed using Table 61. Fault trees RMR_R, RMR_L and RMR_M are provided in Figures 62 and 63.

6.3.4.2 Risks External to Line Pipe--

The relative severity of spills or the risks external to the line from accidental spills can be computed using information supplied in this section.

First, the correction factor CF_{ED} for risks external to the line are computed using Table 62. Then the values for risks external to the line can be computed using Table 63; this is accomplished by taking the product of the risk correction factor CF_{ED} and the previously computed risks (see Section 6.3.4) that petroleum will escape from the line. Spillage risks external to line pipe can be computed in Table 63 for the following:

• Spills	
- Frequence	F_{SE}
- Volume	V_{SE}
• Spill size	
- Rupture (nominal largest)	V_{SRE}
- Leak (nominal largest)	V_{SLE}
- Mean	V_{SME}
• Relative measure of risk	
- Rupture	RMR_{SRI}
- Leak	RMR_{SLE}
- Mean	RMR_{SME}

If, for example, the nominal largest rupture size V_{NLRC} were 5000 barrels for a particular line located in an urban area, the risk correction factor is:

$$CF_{ED} = CF_{FT} \times CF_{UW} \times CF_W \times CF_I \times CF_P \times CF_C \times CF_{UF} \times CF_{ST} \times CF_{NP} \times CF_{SC}$$

$$= 1 \times 1 \times 1 \times 1 \times 100 \times 1 \times 1 \times 1 \times 1 \times 10 = 1000.$$

TABLE 59. CALCULATION OF THE FREQUENCY F_{STC} AND VOLUME V_{STC} OF SPILLS FOR LINE PIPE

	SPILL FREQUENCY								SPILL VOLUME								
	Reference Line Pipe(1)	Frequency Correction Factors(2)						Line Pipe	Reference Line Pipe	Volume Correction Factors(3)							Line Pipe
		Individual Variations					Cumulative		(Spill Volume)	Individual Variations						Cumulative	
		Age	Geometry	Length	Use	Spill Size	$CF_a \times CF_g \times CF_l \times CF_u \times CF_{ss} =$	$F_{ST} \times CF_F =$		Diameter	Length	Use	Pumping Station Shut-down	Mainline Valve Closure	Line Elevation	$CF_d \times CF_l \times CF_u \times CF_{ps} \times CF_{mc} \times CF_{le} = CF_{SV}$	$V_{ST} \times CF_{SV} =$
Type of Line	F_{ST} Spills/Year	CF_a	CF_g	CF_l	CF_u	CF_{ss}	CF_F	F_{STC}	V_{ST} Barrels/Year	CF_d	CF_l	CF_u	CF_{ps}	CF_{mc}	CF_{le}		V_{STC} Barrels/Year
Crude Gathering Line																	
Onland																	
Underwater																	
Crude Trunkline																	
Onland																	
Underwater																	
Product Trunkline																	
Onland																	
Underwater																	
TOTAL																	

Note: (1) See Table 4-1.
(2) See Figure 4-7.
(3) See Figure 4-9.

TYPING GUIDE SHEET

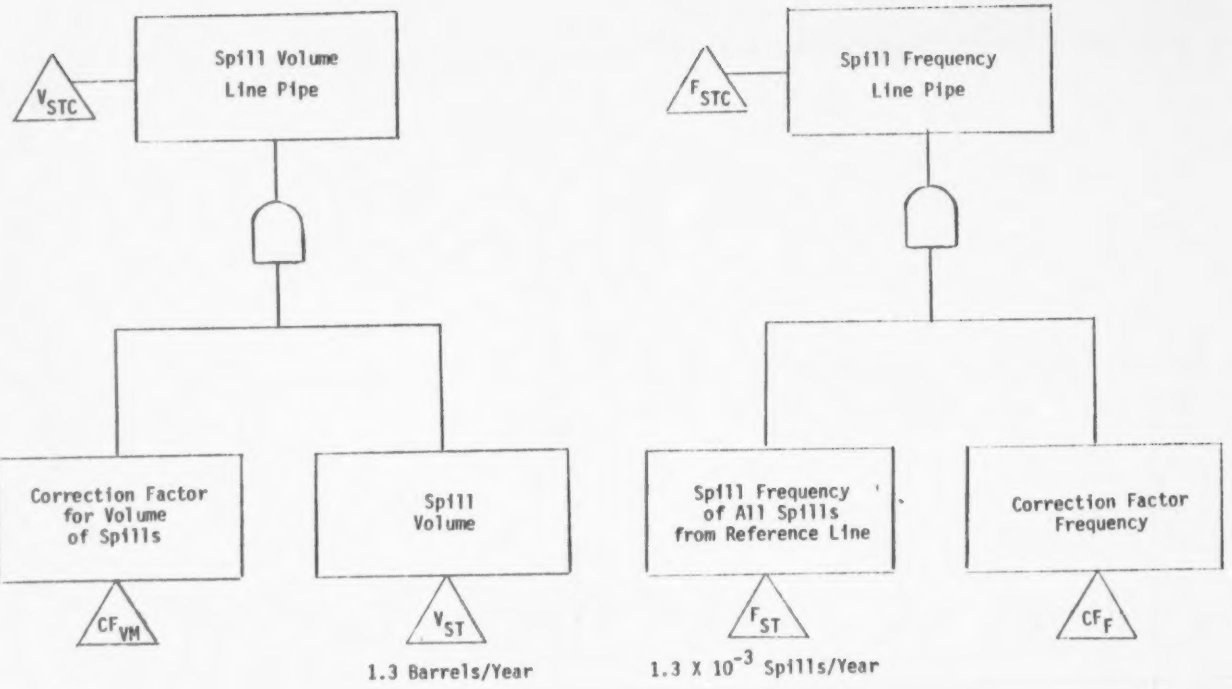

Spill Volume Line Pipe
V_{STC}
Correction Factor for Volume of Spills
CF_{VM}
Spill Volume
V_{ST}
1.3 Barrels/Year
Spill Frequency Line Pipe
F_{STC}
Spill Frequency of All Spills from Reference Line
F_{ST}
1.3 X 10^{-3} Spills/Year
Correction Factor Frequency
CF_F

Figure 60. Fault trees, V_{STC} and F_{STC}, frequency and mean volume of spills from line pipe.

BEGIN FIRST LINE OF TEXT HERE

DROPPED HEAD: BEGIN SECTIONS HERE

TOP OF IMAGE AREA

TABLE 60. CALCULATIONS OF THE NOMINAL LARGEST SIZE OF RUPTURES, V_{NLRC}, LEAKS$_{NLLC}$ AND MEAN V_{MC} FOR LINE PIPE SPILLS

	NOMINAL LARGEST RUPTURE SPILL V_{NLRC}							NOMINAL MEAN SPILL SIZE V_{MC}			NOMINAL LARGEST LEAK SPILL SIZE V_{NLLC}				
	Reference Line Pipe(1) (Nominal Largest Ruptured Spill Size)	Volume Correction Factors(2)					Line Pipe	Reference Line Pipe(1) (Mean Spill Size)(3)	Cumulative Volume Correction Factor	Line Pipe	Reference Line Pipe(1) (Nominal Largest Leak Spill Size)				Line Pipe
		Individual Variations				Cumulative						Individual Variations		Cumulative	
		Diameter	Pumping Station Shutdown	Mainline Valve Closure	Line Elevation	$CF_d \times CF_{ps} \times CF_{mc} \times CF_{le} =$	$V_{NLR} \times CF_{VR} =$			$V_M \times CF_{VM} =$		Line Elevation		$CF_{lc} =$	$V_{NLL} \times CF_{VL} =$
Type of Line	V_{NLR} (Barrels)	CR_d	CF_{ps}	CF_{mc}	CF_{le}	CF_{VR}	V_{NLRC} (Barrels)	V_M (Barrels)	CF_{VR}	V_{MC} (Barrels)	V_{NLL} (Barrels)	CF_{le}		CF_{VL}	V_{NLLC} (Barrels)
Crude Gathering Line															
Onland															
Underwater															
Crude Trunkline															
Onland															
Underwater															
Product Trunkline															
Onland															
Underwater															
TOTAL															

Note: (1) See Table 4-1.
(2) See Figure 4-9.

BEGIN LAST LINE OF TEXT

PAGE NUMBER

EPA Form 2350-4 (4-80)

TYPING GUIDE SHEET

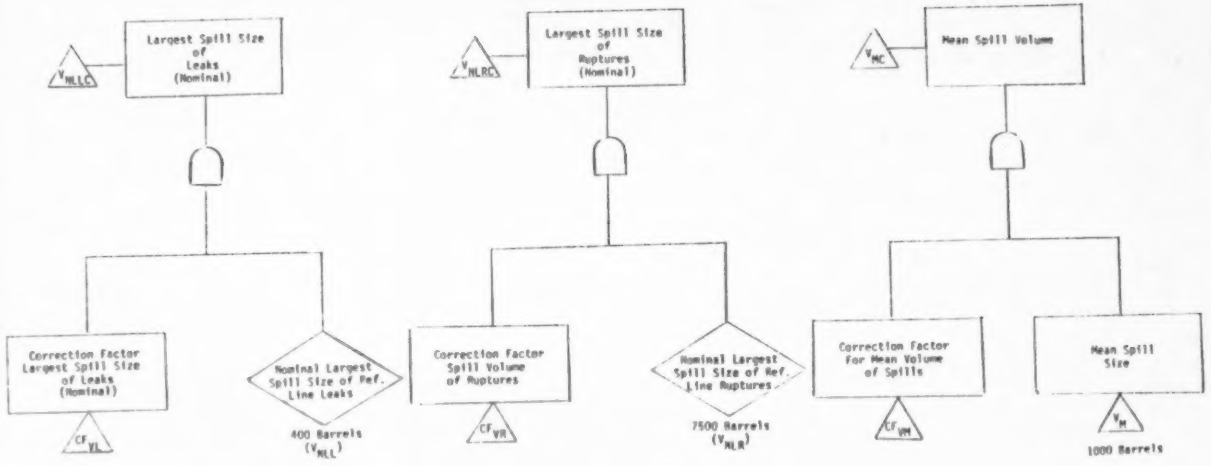

Largest Spill Size of Leaks (Nominal)
V_{NLLC}
Correction Factor Largest Spill Size of Leaks (Nominal)
CF_{VL}
Nominal Largest Spill Size of Pef. Line Leaks
400 Barrels (V_{NLL})
Largest Spill Size of Ruptures (Nominal)
V_{NLRC}
Correction Factor Spill Volume of Ruptures
CF_{VR}
Nominal Largest Spill Size of Ref. Line Ruptures
7500 Barrels (V_{NLR})
Mean Spill Volume
V_{MC}
Correction Factor For Mean Volume of Spills
CF_{VM}
Mean Spill Size
V_M
1000 Barrels

Figure 61. Fault trees, V_{NLLC}, V_{NLRC}, V_{MC}, nominal largest size of ruptures, leaks and mean for line pipe spills.

TABLE 61. CALCULATIONS OF THE RELATIVE MEASURE OF OIL SPILL RISKS FOR RUPTURE RMR_R, LEAKS RMR_L AND MEAN SIZE RMR_M SPILLS FOR LINE PIPE

	Relative Measure of Rupture Spill Risk RMR_R				Relative Measure of Leak Spill Risk RMR_L				Relative Measure of Mean Spill Risk RMR_M			
Type of Line	V_{NLRC} (1)	$0.25\ F_{ST}$ (2)	CF_F (3)	$V_{NLRC} \times 0.25\ F_{ST} \times CF_F = RMR_R$	V_{NLLC} (1)	$0.75\ F_{ST}$ (2)	CF_F (3)	$V_{NLLC} \times 0.75\ F_{ST} \times CF_F = RMR_L$	V_{MC} (1)	F_{ST} (2)	CF_F (3)	$V_{MC} \times FST \times CF_F = RMR_M$
Crude Gathering Line												
Onland												
Underwater												
Crude Trunkline												
Onland												
Underwater												
Product Trunkline												
Onland												
Underwater												
Total												

Note: (1) See Table 4-5.
(2) See Table 4-1.
(3) See Table 4-4.

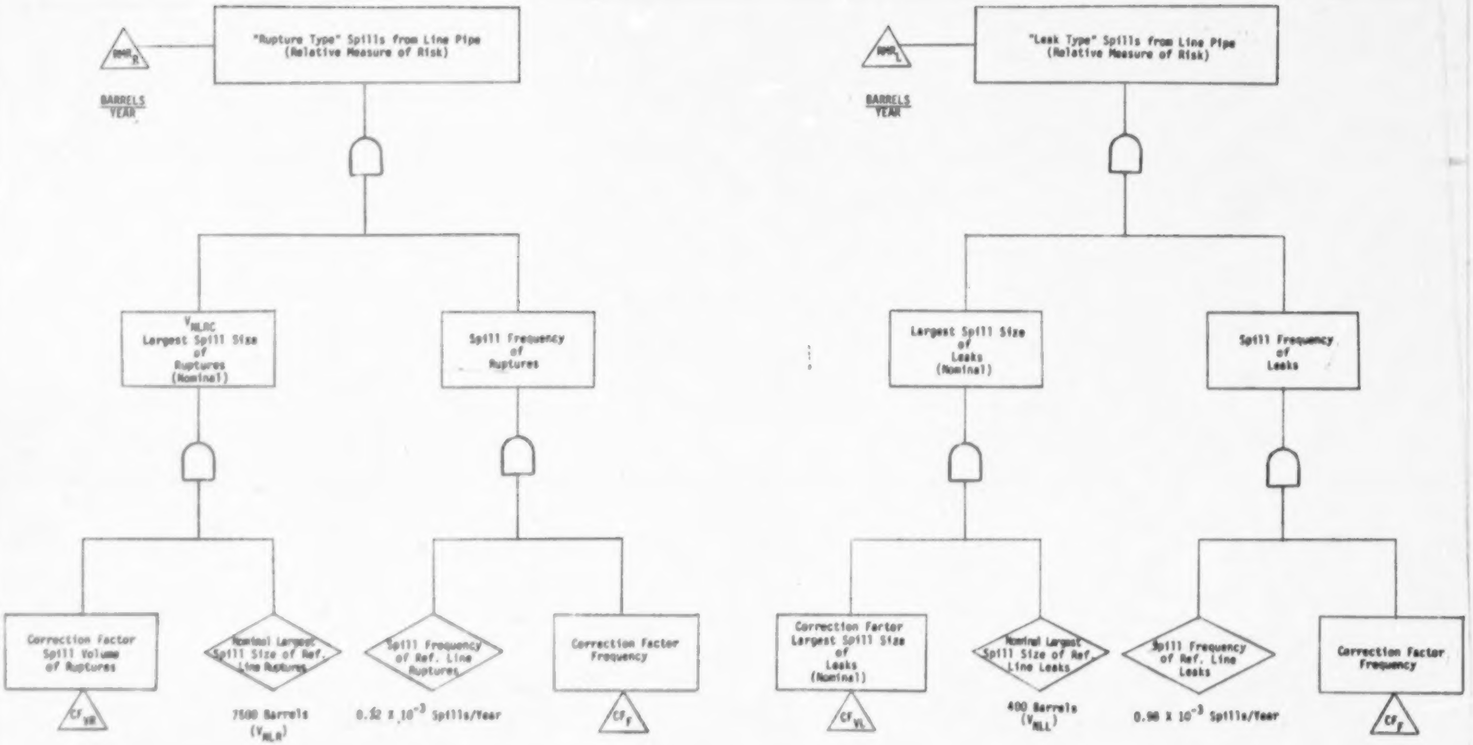

RMR_R
BARRELS/YEAR
"Rupture Type" Spills from Line Pipe (Relative Measure of Risk)
V_{NLRC} Largest Spill Size of Ruptures (Nominal)
Spill Frequency of Ruptures
Correction Factor Spill Volume of Ruptures
CF_{VR}
Nominal Largest Spill Size of Ref. Line Ruptures
7500 Barrels (V_{NLR})
Spill Frequency of Ref. Line Ruptures
0.52×10^{-3} Spills/Year
Correction Factor Frequency
CF_F
RMR_L
BARRELS/YEAR
"Leak Type" Spills from Line Pipe (Relative Measure of Risk)
Largest Spill Size of Leaks (Nominal)
Spill Frequency of Leaks
Correction Factor Largest Spill Size of Leaks (Nominal)
CF_{VL}
Nominal Largest Spill Size of Ref. Line Leaks
400 Barrels (V_{NLL})
Spill Frequency of Ref. Line Leaks
0.98×10^{-3} Spills/Year
Correction Factor Frequency
CF_F

Figure 62. Fault trees, RMR_R, RMR_L, relative measure of risks (barrels/year) of ruptures and leaks from line pipe.

BEGIN FIRST LINE OF TEXT HERE
CENTER OF PAGE
DROPPED HEAD FOR SECTIONS HERE

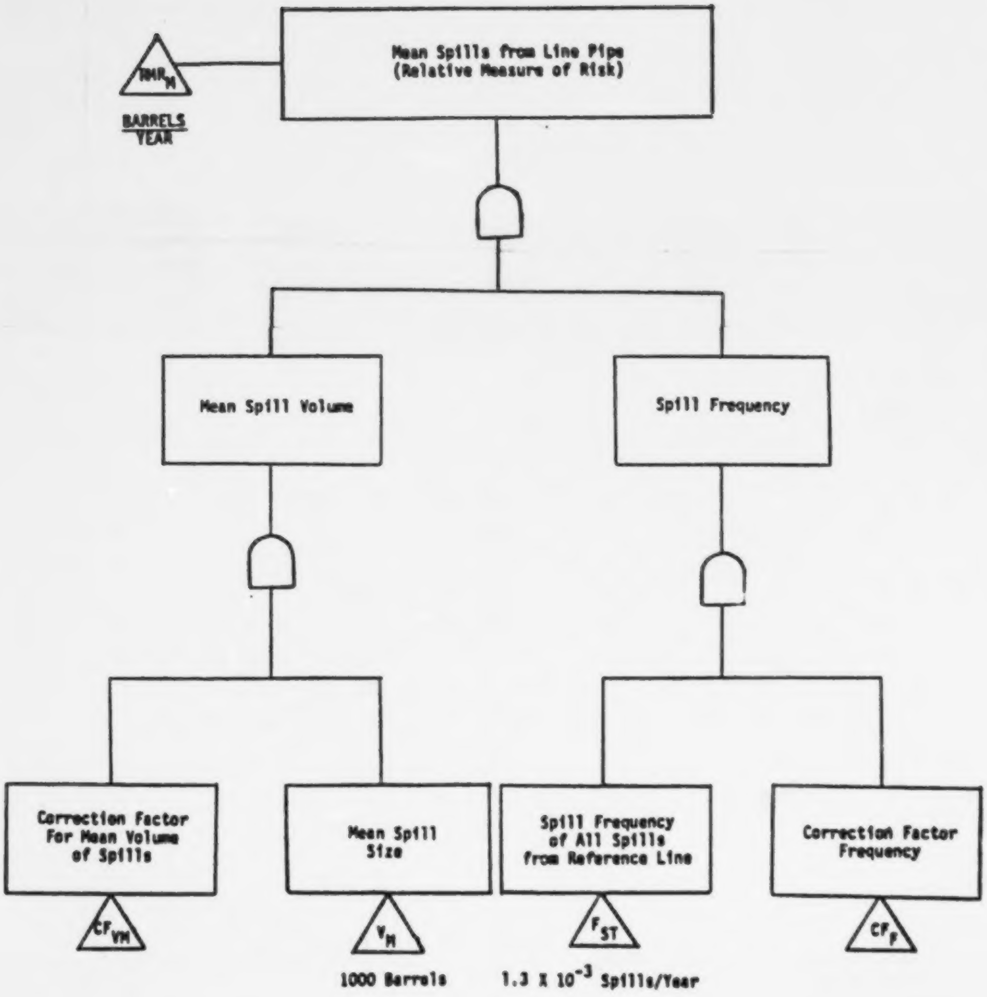

Mean Spills from Line Pipe (Relative Measure of Risk)
RMR_M
BARRELS / YEAR
Mean Spill Volume
Spill Frequency
Correction Factor For Mean Volume of Spills
CF_{VM}
Mean Spill Size
V_M
1000 Barrels
Spill Frequency of All Spills from Reference Line
F_{ST}
1.3×10^{-3} Spills/Year
Correction Factor Frequency
CF_F

Figure 63. Fault tree, RMR_M, relative measure of risk (barrels/year) of mean spills from line pipe.

TYPING GUIDE SHEET

TABLE 62. CALCULATIONS OF THE CORRECTION FACTOR CF_{ED} FOR RISKS EXTERNAL TO LINE PIPE

Type of Line	Individual Variations										Cumulative $CF_{FT} \times CF_{UW} \times CF_W \times CF_I \times CF_P \times CF_C \times CF_{UF} \times CF_{ST} \times CF_{NP} \times CF_{SV} = CF_{ED}$
	Fluid Transported CF_{FT}	Underground Water Supplies CF_{UW}	Water CF_W	Industrial CF_I	Population CF_P	Commercial CF_C	Underground Facilities CF_{UF}	Surface Transportation CF_{ST}	Natural Preserves CF_{NP}	Spill Volume CF_{SV}	
Crude Gathering Line											
Onland											
Underwater											
Crude Trunkline											
Onland											
Underwater											
Product Trunkline											
Onland											
Underwater											

Note: See Table 4-3.

TABLE 63. CALCULATIONS OF RISKS EXTERNAL TO LINE PIPE

Type of Line	Spills		Spill Size			Relative Measure of Spill Risk		
	Frequency $F_{ED} \times F_{STC} = F_{SE}$	Volume $C_{FED} \times V_{STC} = V_{SE}$	Rupture Nom. Largest $C_{FED} \times V_{NLRC} = V_{SRE}$	Leak Nom. Largest $C_{FED} \times V_{NLLC} = V_{SLE}$	Mean $C_{FED} \times V_{MC} = V_{SME}$	Rupture $C_{FED} \times RMR_R = RMR_{SRE}$	Leak $C_{FED} \times RMR_L = RMR_{SLE}$	Mean $C_{FED} \times RMR_M = RMR_{SME}$
Crude Gathering Line								
Onland								
Underwater								
Crude Trunkline								
Onland								
Underwater								
Product Trunkline								
Onland								
Underwater								
Total								

Hence, the relative severity or risk external to the line V_{SRE} is:

$$V_{SRE} = 5000 \text{ barrels} \times 1000 = 500{,}000 \text{ barrels} \quad .$$

Thus, the indicated spill is considered to be equivalent to a 500,000 barrel spill from the reference line.

SECTION 7

ANALYSIS OF THE REDUCTION OF THE RISK OF OIL SPILLS FROM LINE PIPE BY UTILIZATION OF LEAK DETECTION AND INSPECTION METHODS

The potential of selected leak detection and inspection methods to reduce the risk[a] of oil spills (frequency and volume of spills and risks external to the line) from petroleum pipeline systems is estimated in this section. Means are also provided to enable an operator to estimate the risk reduction capabilities (effectiveness) of inspection and leak detection methods for his own line. Since costs are a major consideration in a practical maintenance program for line pipe, costs of the various options (inspection and leak detection methods) and spillage are estimated and a cost-effectiveness analysis carried out.

Means for reducing the risk of line pipe spills are examined in detail in Section 7.1. First, the most promising inspection and leak detection methods were selected based on a selection criteria. Then estimates made of the capabilities of leak detection and inspection equipment to detect a leak of a certain magnitude and/or impending failures. The methods are evaluated based on their capability to reduce the frequency and volume of "leak type" and "rupture type" spills for the reference line. Factors are established which provide a simple means of comparing the capability of methods to reduce the frequency and volume of spills. These factors help a potential user select the most suitable method to satisfy the spill prevention programs needs of a particular line.

The amount of oil spillage that can be prevented is examined in Section 7.2. Accidental oil spillage that exists for line pipe is first estimated. Then estimates are made of spillage that can be prevented by implementation of various scheduled inspection and leak detection systems. This is done for all U.S. lines and the reference line. Means are provided so that quantitative values of spillage and prevention of spillage can be determined for most lines.

Section 7.3 contains a cost analysis of inspection and spillage.

A cost-effectiveness analysis of the selected inspection and leak detection methods for various inspection schedules was provided in Section 7.4. Two measures of cost-effectiveness were used in the analysis.

---

[a] Means are provided in Section 6 to enable an operator to estimate the risk of oil spills for his own line.

7.1 COMPARISON AND EVALUATION OF LEAK DETECTION AND INSPECTION METHODS

This section provides an in-depth comparison and evaluation of leak detection and inspection methods that appear to be the most promising. An oil spill risk reduction analysis is carried out for these selected methods. This information is then used to estimate detectable and undetectable spillage for the reference line pipe and for all U.S. lines in Section 7.2.

The most promising methods are reviewed in the first subsection. General guidelines and criteria for method selection are presented. Methods selected for further evaluation are identified and categorized by optimum use, i.e., reducing one or both parts of the oil spill risk.

An analysis of the risk reduction capabilities of the selected methods is carried out in the second subsection. Methods are analyzed as to their capability of reducing the volume and frequency of "leak type" and "rupture type" spills for both onland and underwater use. Risk reduction factors are estimated for all methods and combinations of methods. In order to simplify comparisons, normalized risk reduction values, based on a single reference inspection, are provided. Using these values, for example, the effectiveness of one inspection can be equated to a certain number of other inspections, i.e., one inspection pig survey to a number of visual inspections of the line.

7.1.1 Selection of the Most Promising Leak Detection and Inspection Methods

7.1.1.1 Guidelines--

No single inspection or leak detection method currently exists that is capable of detecting all leaks in sufficient time to avoid an oil spill incident. This situation exists for a number of reasons such as:

- Variety of line pipe systems
- Accidental spillage may occur at any location along the line
- Wide variations in the frequency and volume of spills
- Numerous causes of spills.

Despite these difficulties, this report shows that the potential exists for significant reductions in the volume and frequency of petroleum spillage both for individual lines and those nationwide. In this study, the major emphasis is for reductions of spillage nationwide. However, means are provided in Section 6 for identifying and quantifying the risks of both individual lines such as those located in potentially high risk areas and lines nationwide and in Section 7 for estimating the reduction of risks using the most promising methods. On a nationwide basis, maximum oil spill risk reduction is accomplished by implementation of spill prevention programs incorporating methods that adhere to the following guidelines:

- Adaptable to most lines
- Highly effective in reducing frequency of spills, particularly those that are expected to result in ruptures
- Highly effective in limiting the spill size
- Cost-effective.

In high-risk areas, however, emphasis is placed on reducing the frequency and volume of all spills to as low a level as practical for the specific type of line. Hence, methods considered highly effective but, for example, not adaptable to most lines are considered for use in individual spill prevention programs for optimum spill reduction.

7.1.1.2 Selection Criteria--

Selecting the most promising inspection and leak detection methods was based on the following criteria:

- Must be adaptable to most onland lines
- Must be adaptable to most underwater lines
- Must have a potential for a significant reduction in the frequency or volume of spills
- Practical implementation and operation costs
- Limited interference with pipeline operations
- Rapid response for "rupture type" spills
- Inspections can be performed either by semi-skilled line pipe personnel or inspection services
- High reliability or high probability that the equipment will operate satisfactorily during the inspection
- High design adequacy or probability that the inspection equipment will accomplish its performance requirements.

7.1.1.3 Methods Selected for Further Evaluation--

Applicable methods were briefly described and compared in Section 5.3. Of these, only a few leak detection and inspection methods were judged to satisfy the general guidelines and selection criteria for line pipe. The methods selected for further evaluation are identified in Table 64. Generally, the methods selected are highly effective in reducing one of the two parts of the oil spill risks, i.e., reducing either the volume of spills (Section 5.2.4.2) or the frequency of spills (Section 5.2.4.1). In a few cases, a selected method may be effective for both parts. Therefore, methods are identified as to their optimum use, i.e., reducing one or both parts of the oil spill risk.

Although not selected, some leak detection and inspection methods may be effective in solving atypical spill problems that are characteristic of a particular line or small group of lines. For these special applications,

BEGIN FIRST LINE OF TEXT HERE
CENTER OF PAGE
TOP OF IMAGE AREA
DROPPED HEAD BEGIN SECTIONS HERE

TABLE 64. INSPECTION AND LEAK DETECTION METHODS SELECTED FOR FURTHER EVALUATION OF LINE PIPE

	Reduction of Size of Spill		Reduction of Frequency of Spill (1)							
					Causes					
					Line Pipe Faults			Outside Forces		
Leak Detection and Inspection Method	Leaks	Ruptures	Leaks	Ruptures	Defects	External Corrosion	Internal Corrosion	Equipment Rupturing Line	Damage by Excavation Equipment	Other
1. Visual inspection by air or ground patrol in excess of required inspections			X	X	X	X	X	X	X	X
2. Visual inspection by ground patrol with hydrocarbon detector or other comparable device	X	X	X	X	X	X	X	X	X	X
3. Hydrocarbon probe-towfish or similar device - Underwater lines only - All lines	X		X IND	X X	X X	X X	X X			
4. Oil spill detectors - Marine terminal or platform - Total line pipe mileage	X	X								
5. Pressure deviations a. Pump stations (existing method) b. Along line		X X								
6. Flow rate a. Deviations b. Comparisons (computerized)		X X								
7. Volume comparisons (computerized)		X								
8. Mathematical modeling (computerized)	X	X								
9. Negative pressure surge (computerized)		X								
10. Passive acoustic array (computerized)	X	X	X	X	X	X	X	X	X	
11. External rods with passive acoustic sensors	X	X								
12. Pressure static	X	X								
13. Hydrostatic	X		X	X	X	X	X			
14. Pressure difference	X		X	X	X	X	X			
15. Change or add inhibitors as needed			X	X			X			
16. Inspection of sample of line for wall thickness by ultrasonic or comparable technique			X	X	X	X	X			
17. Survey by inspection pig-magnetic flux type or other comparable device			X	X	X	X	X			
18. Depth of cover inspection by sonar (sidescan and penetrating) or other comparable device - Underwater lines only - All lines			IND IND	X X				X X	X X	
19. Charting of line pipe - Underwater lines only - All lines			X IND	X IND	X IND					
20. Preventive program for outside forces (Reference 12)-one call system	X		X	X	X	X	X	X	X	X
21. Pig line for water removal			X	X			X			
22. Other - Cathodic protection system installation and maintenance			X	X		X				
- Visual inspection (biweekly) by air or ground patrol (required inspection)	X		X	X	X	X	X	X	X	X

Note : (1) IND - Improvement not discernible

BEGIN LAST LINE OF TEXT
BOTTOM OF IMAGE AREA OUTSIDE DIMENSION FOR TABLES AND ILLUSTRATIONS

PAGE NUMBER
EPA Form 2230-1 (9-80)
TYPING GUIDE SHEET

the operator should consider the potential of other methods described in Section 5.3.

The most commonly used spill prevention methods for operating lines currently required by U.S. government regulations are included in Table 64 for comparison purposes only. These methods, mainly bimonthly visual line inspections and monitoring of cathodic protection systems, have already affected some limited spill prevention. Cathodic protection systems, for example, are considered to be responsible for some of the reduction of "leak type" spills caused by external corrosion of line pipe.

7.1.2 Analysis of the Capabilities of the Selected Methods to Reduce the Oil Spill Risk (Volume and Frequency of Spills)

For the purpose of this study, a spill reduction analysis can be best accomplished by evaluating and comparing the methods that are applicable to each part of the risk[a]. Therefore, the capability of selected methods to reduce the volume and the frequency of spills are discussed and analyzed in separate subsections.

Methods for onland lines are generally assumed in the analysis. These methods normally apply to both onland and underwater lines.

Methods that might be particularly effective for only underwater lines or lines close to water supplies are also included in the analysis. This is done even though these methods would not contribute to a significant[b] reduction in the volume or frequency of spills nationwide. The reason these methods are included is that high reduction of the frequency and/or volume of spills from underwater lines can result in a significant reduction in the nationwide total of serious spills. This is because of the high risk to the external environment from even low volume oil spills in underwater lines.

A general discussion of factors that affect the capability to reduce the volume and frequency of spills is presented in the subsections that follow. Then a spill reduction analysis is carried out for methods that reduce the volume and frequency of spills. Selected leak detection and inspection methods are identified in tables along with inspection frequency,

---

[a] Risks to the external environment are not directly accounted for in the reduction analysis based on only the frequency and volume of spills.

[b] Underwater lines account for less than ten percent of the total line pipe mileage. Hence, even if methods have the capability of significantly reducing spillage from underwater lines, it would have a small effect of the total nationwide.

Other factors that should be considered include:

- System effectiveness
  - Reliability
  - Operational readiness
  - Design adequacy
- False alarms
- Other.

The effect of each of these factors varies widely depending upon the implementation of each method. It also depends on whether the method is used for detection of rupture and/or leaks. The combined effects of these characteristics along with these other considerations determine the overall capability of a method to reduce the volume of a spill. Hence, each is considered in the evaluation of selected methods.

Implementation of leak detection and inspection methods that are capable of adequately satisfying the required characteristics potentially will not only prevent major pollution incidents but will significantly reduce the annual loss of oil. Hence, implementation of methods that are effective in reducing the size of an accidental spill is an important consideration in a spill prevention and control program. It should be noted, however, that methods effective in reducing spill volume generally are not highly effective in preventing spills or reducing the frequency of spills.

Various leak detection and inspection methods to varying degrees can be implemented to detect a spill before the volume becomes large enough to cause a major pollution incident. Table 65 compares the characteristics of selected methods for use on the reference line, assuming stable flow[a]. Values are included for the fcur major system characteristics (sensitivity, response, inspection frequency and leak location). For analysis purposes, single values are presented in the table. However, wide variations in sensitivity are possible in implementing certain methods. These variations result from the variety of systems, equipment variations, operational procedures and other factors. Values given in the table and figures are not optimum. However, these are considered typical of modern installations and achievable for most lines. Many of the values presented in the table are only rough estimates because the information available is insufficient for more accurate estimates. This is often the case for new or experimental methods. Additional details of specific systems are available from the manufacturers indicated in Appendix E and from References 14, 58 and 60.

---

[a] During the periods when significant line transients exist, many methods are much less effective than indicated.

TABLE 65. COMPARISON OF THE SELECTED METHODS FOR DETECTION AND LOCATION OF REFERENCE LINE LEAKS AND RUPTURES

Inspection or Leak Detection Method	Leaks				Ruptures				Inspections Frequency	Location Accuracy %
	Sensitivity		Response Time (1) Long-Term	Loss Sensitivity x Response Time x 2 (barrels)	Sensitivity		Response Time (1) Term	Loss Sensitivity x Response Time x 2 (barrels)		
	Percent Throughout	Barrels/Hour			Percent Throughout	Barrels/Hour				
CONTINUOUS MONITORING										
Pressure deviations pump station along line pipe	NS	NS	NS	NS	20 2	100 50	1 hr. 10 hrs	1000 1000	Continuous	None
Flow rate deviation comparison (computerized)	NS 1	NS 25	NS 1 hr.	NS 50	>5 <4	125 100	1 hr. < 2 min.	250 6.6	Continuous Continuous	None None
Volume comparisons (computerized)	0.3 0.6	7.5 15	24 hours 1 hour	180 30	<3	75	10 min.	25	Continuous	None
Mathematical modeling (computerized)	0.1 0.2	2.5 5.0	24 hours 1 hour	36 10	0.5	25	< 2 min.	< 1	Continuous	None
Negative pressure surge (computerized)	NA	NA	NA	NA	5	125	< 2 min	31	Continuous	± 2 miles
Passive acoustic array - New line - Retrofit	<.2 NS	2.0 NS	20 min. NS	<1 NS	0.5 4	25 100	<1 min. <1 min.	<1 <4	Continuous Continuous	2% of sensor spacing
Oil spill detectors at marine terminal or platform	--	--		small spill	--	--	--	small spill	Continuous	
PERIODIC										
Pressure static	0.1	3	15 min.	.75	0.1	3	15 min.	< 1	After indication of large leak	None
Hydrostatic	0.03	0.7	24 hours	16.8	NS	NS	NS	NS	2	None
Pressure difference	0.002	0.06	72 horus	4.3	NS	NS	NS	NS	2	Between block valves
External rods with passive acoustic sensors	0.2	5.0	<2 min. (3)	--	0.2	5.0	<2 min (3)	--	After indication of large leak	5% of sensor spacing
Visual inspections by air or ground patrol for indication of a spill	--	--	200 hours	minor spill	NS	NS	200 hours	--	26	--
Visual inspection by ground patrol with hydrocarbon probe or comparable device for indications of spill	< 0.002	< 0.06	200 hours	small spill	< 0.002	< 0.06	200 hours	--	26	Few feet

NOTES: (1) NS - Not suitable for indicated detection of leaks or ruptures.

(2) INA- Information is unavailable.

(3) Assumes sytem operational after leak or rupture indication.

TYPING GUIDE SHEET

The most important capability in reducing the volume of spills, for both leaks and ruptures, is the sensitivity or accuracy of the particular methods. A high leak sensitivity, i.e., a few barrels per hour, provides the capability of detecting spillage before a large volume of petroleum can escape from the line.

High sensitivity, however, does not necessarily guarantee that a spill can be detected and the spill volume reduced. Both the frequency of the inspection and response time must also be considered. Frequent or continuous inspection methods with good sensitivity are mandated for detecting rupture type spills. In contrast, high sensitivity methods that require longer response time and less frequent inspections are often suitable for detecting small leaks. Rapid response time[a] (few minutes) is necessary for ruptures, whereas long-term response (1 to 24 hours) is usually suitable for leaks. For example, a typical volume comparison system may be capable of detecting a leak of 0.3 percent of throughput, but the leak must exist for 24 hours before an alarm would be activated. In the case of the reference line, such a system would permit 180 barrels of spillage over a 24-hour period before detection.

The capability of providing accurate leak location, i.e., within a few feet, is also important. This capability is particularly advantageous in certain high-risk areas. For example, spills from elevated lines in rough terrain may continue (because of static head) even though the line is shut down and the mainline valve closed. Location of a spill by conventional air patrol might be quite time consuming and extremely difficult to carry out in darkness, bad weather or dense foliage. A serious pollution incident could occur. This could be avoided if a method that accurately locates leaks were installed at the elevated sections of the line.

Other factors such as system effectiveness and false alarms are also important considerations. False alarms, however, are generally accounted for in the system sensitivity and response. System effectiveness depends upon the specific system and will not be discussed further in this section. It should be considered for each specific installation.

In addition to the capabilities of methods to reduce the volume of spillage, sufficient information must be known about the actual spills. This is important in selecting the most suitable methods for certain types of spills. It is also important for defining spills so that estimates can be made of the oil spill risk reduction that is achievable with each method. The information needed for each accident includes:

- Geometry, dimensions and location on the line pipe of the source of the escaping petroleum
- Volume of fluid lost as a function of time
- Spill volume

---

[a] Response time is defined here as the time duration required to positively identify a spill so that the system can be shut down.

- Time the leak was detected and by what means
- Time the pumping station was shut down after detection of spill
- Time the mainline valve closed
- Type of soil
- Other.

Much of this information is not available. In this study, however, estimates and assumptions are made to account for this lack of information. For example, leak-type spills are assumed to have low flow rates (less than a few barrels per hour) with losses ranging from 1 to 400 barrels. Thus, approximately ten percent of the reported spill volume is attributed to leaks; the remainder is attributed to ruptures. (These percentages were obtained from Table 19).

A reduction analysis of the spill volume for ruptures and leaks is presented for the selected methods in the subsections that follow.

7.1.2.1.1 Estimation of the Capability of Reducing Rupture Volume Using the Selected Methods

Selected methods for reduction of the volume of rupture type spills are shown in Table 66. Frequency of inspection, percent reduction of spill volume, risk reduction factors and normalized values for risk reduction are also included in the table. A single visual inspection in excess of the required bimonthly inspections by air or ground patrol, is the reference inspection. Bimonthly visual line inspections, periodic monitoring of cathodic protection systems, and the monitoring of pressure deviations at the pump stations are considered to be the commonly used methods during the reference year for detection of ruptures. Methods are evaluated primarily on the basis of the product of sensitivity and short-term response time. However, effects of line transients on the capability of a method to detect ruptures are also considered.

In the analysis performed in this section, ruptures and large-size breaks are assumed to account for approximately 90 percent of the volume spilled. Also, ruptures and large size breaks are assumed to typically result in spill rates in excess of five percent of throughput. Hence, for the reference line (flow rate of 2,500 barrels per hour), this type of spill would result in a loss in excess of 125 barrels per hour.

Spill statistics in Section 4 (see Table 19) indicate that over 90 percent of the spill volume results from spills in excess of 400 barrels, and over 80 percent result from spills in excess of 1,000 barrels. Thus, methods that can limit the spill volume to less than 1,000 barrels (about four percent of average hourly throughput) would conceivably eliminate approximately 72 percent of the spill volume.

TABLE 66. SPILL REDUCTION ANALYSIS FOR VOLUME OF RUPTURES FOR TYPICAL SECTION OF LINE PIPE

	Ruptures[1,2,3]				
		% Reduction of Spill Volume			
Inspection or Leak Detection Method	Inspections Frequency/ Year	Indicated Inspections	Single Inspection	Risk Reduction Factor[4] (RRF_{VR})	Risk Reduction Normalized[5]
1. Visual inspections by air or ground patrol for indication of a spill (Required inspection--existing method)	26	0	0	1	NA
2. Visual inspections by air or ground patrol in excess of required inspections	26(Ref) 338	5 40	0.19(Ref) 0.12	0.95 0.6	1.0(Ref) 0.6
3. Visual inspection by air or ground patrol with hydrocarbon probe or comparable device indication of a spill	26 338	5 40	0.19 0.12	0.95 0.6	1.0 0.6
4. Hydrocarbon probe-towfish or similar device					
- Underwater lines only	after indication of spill	IND	IND	IND	IND
- Total line pipe mileage	after indication of spill	IND	IND	IND	IND
5. Oil spill detectors					
- Marine terminal or platform	continuous	30	30	0.7	153
- Total line pipe mileage	continuous	IND	IND	IND	IND
6. Pressure deviations					
a. Pump stations (existing method)	continuous	0	0	NA	NA
b. Along line	continuous	10	10	0.9	53
7. Flow rate					
a. Deviations	continuous	20	20	0.8	105
b. Comparisons (computerized)	continuous	40	40	0.6	210
8. Volume comparisons (computerized)	continuous	70	70	0.3	368
9. Mathematical modeling (computerized)	continous	90	90	0.1	474
10. Negative pressure surge (computerized)	continuous	33	33	0.7	174
11. Passive acoustic array (computerized)	a. continuous[6] b. continuous[7]	60 70	60 70	0.4 0.3	315 368
12. External rods with passive acoustic sensors	after indication of rupture[8]	10	3.3	0.9	17.3
13. Pressure static	after indication of rupture[8]	20	6.6	0.8	34.6
14. Hydrostatic	NS	NS		NS	NS
15. Pressure difference	NS	NS		NS	NS
16. 11(a) and 13	continuous	70	70	0.3	122
17. 11(b) and 13	continuous	80	80	0.2	237
18. 6(a), 7(b), 8	continuous	80	80	0.2	421
19. 6(a), 7(a), 7(b), 8, 10	continuous	95	95	0.05	500
20. 10, 13	continuous	50	50	0.5	263

Notes:

1. NA-Not applicable since method was commonly used for year when risks were determined.
2. NS-Not suitable for indicated detection of leaks or ruptures.
3. IND-Improvement not discernible.
4. Risk of oil spills after applying the inspection method is the product of this factor and the risk value with current requirement and commonly used methods. The value is obtained by subtracting the percent reduction from 1.0.
5. Risk reduction normalized is the percent reduction from a single inspection divided by the percent reduction resulting from one reference inspection.
6. Retrofit installation.
7. Installation on new line.
8. Assumes frequency of inspection carried out three times a year.

Bimonthly visual line inspections, the only major inspections required by U.S. regulations, are ineffective in reducing the volume of rupture type spills. At a spillage rate of 125 barrels per hour, 42,000 barrels of oil could be spilled between biweekly inspections or 21,000 barrels between weekly inspections. Even for more frequent inspections, i.e., daily, 1,500 barrels of oil typically would be spilled before detection. Considering that spills in excess of 1,500 barrels account for about 70 percent of the total spill volume, reductions in spillage would be expected by more frequent visual line inspections. However, many spills of this magnitude are detected by outside observers. Thus, more frequent inspections are not as effective as indicated; a risk reduction factor of 0.6 was assessed for daily inspections and 0.95 for weekly inspections. Aided bimonthly visual inspections such as using a hydrocarbon probe or other comparable device are not expected to produce any additional reduction in the spill volume that is discernible.

Although there is a trend towards continuous monitoring of lines using advanced computerized methods, most operating companies only monitor pressures at pump stations for indications of ruptures. This method is extremely insensitive and is capable of detecting only rupture type spills close to the pump station; the sensitivity of the method decreases with distance from the pump station. For this method, it has been estimated that, on the average, ruptures resulting in 20 percent of throughput could go undetected for greater than one hour.

Monitoring of pressure deviations along the line reduces the problem of decreased sensitivity with distance. The method is considered only marginally adequate for rupture detection; a risk reduction factor of 0.9 is assessed.

Simple monitoring of flow deviations at one or more stations for indications of rupture is often used by operating companies. Line transients generally require that the alarm setpoint be quite high, i.e., five to ten percent of throughput to eliminate false alarms. The method is considered only marginally adequate for rupture detections; a risk reduction factor of 0.8 is assessed.

An approach to significantly reduce the volume of ruptures is to use one or more of the methods that employ computerized continuous monitoring. Based on the information supplied in Table 66, limiting the spill size to less than 1,000 barrels appears to be relatively easy to accomplish using many of the computerized methods. However, the various transients that occur in the line, such as line pack, pressure changes, flow changes, pump shutdown, etc., make this somewhat more difficult to accomplish. These transients are often accounted for by various measures such as lengthening the time duration of monitoring for a leak alarm, raising alarm setpoints so that the sensitivity is compromised, or using a computerized model that automatically monitors and accounts for these variations.

The mathematical modeling method currently under evaluation on a number of lines, has the potential of being the most effective of all methods surveyed. Despite transients, the method appears to be capable of detecting leakage rates of 0.5 percent of throughput in about two minutes. This would result in a loss of less than one barrel for a typical line before a leak could be detected and verified. This method appears capable of detecting essentially all rupture type spills; a risk reduction factor of 0.1 was assessed.

The flow rate comparison method is also effective in detecting rupture type spills. The method requires that high accuracy meters (0.02 to 0.1 percent of flow) be installed at pumping stations and at inlet and outlet locations. A leak between any two stations results in a characteristic increase in flow rate upstream and a decrease downstream. Because of the unique and characteristic rupture signal, the method is unaffected by many line transients. The method is capable of detecting short-term leaks of less than four percent of throughput in about two minutes. Primarily because the method appears capable of detecting most rupture type spills, a risk reduction factor of 0.6 was assessed.

The computerized volume comparison method continuously monitors the volumes at the input and output of the line. Corrections are normally made for pressure, temperature and other factors. Modern systems incorporating this method routinely detect ruptures of large-sized breaks at better than three percent of throughput over a ten-minute interval. This method is considered to be an excellent means of indicating "rupture type" spills; a risk reduction factor of 0.3 was assessed.

Negative pressure surge method is insensitive to many large-sized breaks but should be capable of rupture detection. A risk reduction factor of 0.66 was assessed.

The passive acoustic array is an experimental method that has the dual capability of rapid detection and accurate location of rupture or large-sized breaks. Sensitivity, reliability and false alarms are uncertain. Considering that the method is unproven on an operational line, a risk reduction factor of 0.3 was assessed. Potentially, a risk reduction factor of 0.1 is possible, primarily because of its ability to locate the rupture.

Two methods in use on a few lines are particularly useful after a rupture or large-sized break is indicated by other means. Passive acoustic sensors installed on rods permanently attached to the line would be a great benefit in high risk areas because of the capability of locating the spill. However, for use on a typical line, a risk reduction factor of only 0.9 is warranted. The pressure static method is particularly well suited for verifying the existence of a large leak which may be slightly below the sensitivity of the leak indication method. A risk reduction factor of 0.8 was assessed for the latter method.

Combinations of leak detection and inspection methods are capable of affecting an improved reduction in the risk of rupture type spills. A few of the more effective combinations are indicated for methods 16 through 20 in Table 66.

In summary, only a few methods are judged to have the potential for significantly reducing the risks, i.e., have a risk reduction factor of better than 0.5. These include:

- Mathematical modeling
- Passive acoustic array
- Volume comparison
- Combinations of pressure, flow and volume comparisons methods
- Pressure deviations, flow rate, volume comparison and negative pressure surge.

Based on normalized risk reduction, the mathematical model method appears most effective of those selected. One such inspection is estimated to be equivalent to 474 visual inspections of the line. The volume comparison method and passive acoustic array are also considered effective; these are estimated to be equivalent to 368 visual inspections of the line.

7.1.2.1.2 Estimating the Capability of Reducing Leak Volume Using Selected Methods

Selected methods for reducing the volume of "leak type" spills (less than 400 barrels) are shown in Table 67 along with frequency of inspection, percent reduction of spill volume, risk reduction factors and normalized values for risk reduction. A single inspection in excess of the required bimonthly visual line inspections is the reference inspection. Biweekly visual line inspections and periodic monitoring of the cathodic protection systems are assumed to be the commonly used methods for detecting leaks. For leak reduction, continuous monitoring methods are evaluated primarily on the basis of the product of long-term response time and sensitivity, periodic methods are evaluated primarily on the basis of sensitivity and frequency of inspection.

In the analysis, leakage of less than 400 barrels is assumed to account for about ten percent of the reported volume of spillage. Line pipe leakage normally is assumed to occur continuously at very low rates (less than a few barrels per hour). However, leaks may often occur intermittently. Reference 78, for example, indicates that for some lines leak rates of approximately 0.7 barrels per hour are required for hair crack type leaks to stay open. Hence, intermittent leaks are also considered in this analysis.

Bimonthly visual line inspections are considered to be marginally effective in reducing the volume of "leak type" spills. For example, a continuous leak of two barrels per hour could spill 336 barrels before detection by biweekly visual inspections.

Assuming the leakage is normally continuous, more frequent visual line inspections would be expected to reduce the volume lost by an amount almost proportional to the inspection frequency. Thus, weekly inspections are judged to reduce the spill volume by about 30 percent; a risk reduction

TABLE 67. SPILL REDUCTION ANALYSIS FOR THE VOLUME OF LEAKS FOR A TYPICAL SECTION OF LINE PIPE

Inspection or Leak Detection Method	LEAKS[1,2,3]				
	Inspections Frequency/Year	% Reduction of Spill Volume		Risk Reduction Factor[4] RRF_{VL}	Risk Reduction (Normalized)[5]
		Indicated Inspections	Single Inspection		
1. Visual inspections by air or ground patrol for indication of a spill (Required inspection--existing method)	26	0	0	NA	NA
2. Visual inspections by air or ground patrol in excess of required inspections	a. 26(Ref)	30	1.15(Ref)	0.7	1.0(Ref)
	b. 338	70	0.21	0.3	0.18
3. Visual inspection by air or ground patrol with hydrocarbon probe or comparable device indication of a spill	a. 26(Ref)	20	4	0.8	3.5
	b. 52	60	2.3	0.6	2.0
	c. 338	80	2.37	0.2	2.0
4. Hydrocarbon probe-towfish or similar device					
- Underwater lines only	6	50	8.33	0.5	7.2
- Total line pipe mileage	6	0.5	0.8	0.95	0.7
5. Oil spill detectors					
- Marine terminal or platform	continuous	50	50	0.5	43.5
- Total line pipe mileage	continuous	5	5	0.95	4.35
6. Pressure deviations					
a. Pump stations (existing method)	continuous	0	0	NA	NA
b. Along line	continuous	NS	NS	NS	NS
7. Flow rate					
a. Deviations	continuous	NS	NS	NS	NS
b. Comparisons (computerized)	continous	NS	NS	NS	NS
8. Volume comparisons (computerized)	continuous	IND	IND	IND	IND
9. Mathematical modeling (computerized)	continuous	20	20	0.8	17.4
10. Negative pressure surge (computerized)	continuous	NS	NS	NS	NS
11. Passive acoustic array (computerized)	a. continuous[6]	IND	INC	IND	IND
	b. continuous[7]	20	20	0.8	17.4
12. External rods with passive acoustic sensors	after indication of leak[8]	10	3.3	0.9	2
13. Pressure static	after indication of leak[8]	20	6.6	0.8	5.7
14. Hydrostatic	after indication of leak[8]	30	10	0.7	8.7
	2	40	20	0.6	17.4
15. Pressure difference	a. 1	30	30	6.7	26
	b. 2	50	25	0.5	21
	c. 12	90	7.5	0.10	6.5
16. 14 and 11 or 14 and 3	2	70	35	0.30	3.0
17. 11 and 13	continuous	30	30	0.7	8.7
18. 6, 7, 8	continuous	IND	IND	IND	IND
19. 6(a), 7(a), 7(b), 10	continuous	IND	IND	IND	IND
20. 10, 13	continuous	IND	IND	IND	IND

Notes:

1. NA-Not applicable since method was commonly used for year when risks were determined.
2. NS-Not suitable for indicated detection of leaks or ruptures.
3. IND-Improvement not discernible.
4. Risk of oil spills after applying the inspection method is the product of this factor and the risk value with current requirement and commonly used methods. The value is obtained by subtracting the percent reduction from 1.0.
5. Risk reduction normalized is the percent reduction from a single inspection divided by the percent reduction resulting from one reference inspection.
6. Retrofit installation.
7. New line installation.
8. Assumed frequency of inspection carried out three times a year.

EPA Form 2250-6 (4-80)
TYPING GUIDE SHEET

factor of 0.7 was assessed. For daily inspections, a risk reduction factor of 0.3 was assessed.

Use of visual aids, such as hydrocarbon probes or other comparable devices, by ground patrol are expected to further reduce the volume spilled. These inspections provide the potential for detecting very small or intermittent spills or spillage that may be trapped and not reach the surface for a long period of time. A risk reduction factor of 0.8 was assessed for aided biweekly inspections by ground patrol, 0.6 for weekly and 0.2 for daily inspections.

Bimonthly periodic inspections of underwater lines using hydrocarbon probes in a towfish system are expected to be quite effective. These inspections are expected to detect small leaks that may not be detected by visual inspections. For example, small leaks that might otherwise be considered as underground seepage could be detected and located. A risk reduction factor of 0.5 was assessed for these inspections. Since only approximately ten percent of line pipes are underwater, the risk reduction factor assessed on a nationwide basis for all lines is 0.95.

Continuous monitoring of internal fluid variations during fluid transfer using pressure, flow rate, and negative surge are not considered suitable for leak detection. Normal operations generally produce line transients that require an operator to raise alarm levels so as to preclude the detection of small to medium sized leaks, i.e., few barrels per hour. The volume comparisons method is only marginally capable of detecting leaks and only under optimum conditions. These methods are expected to provide no discernible improvement over biweekly visual inspections by ground patrol.

Of the remaining continuous monitoring methods, only mathematical modeling and passive acoustic array are considered to be capable (marginally) of detecting medium sized leaks. Risk reduction factors of 0.8 were assessed for these methods.

The method employing rods with passive acoustic sensors has poor sensitivity for leak detection. However, it can be used to reduce the time required to locate an expected leak. Thus, a risk reduction factor of 0.9 was assessed.

Periodic pressure testing methods, unless carried out often, are not particularly beneficial. The pressure difference method is the most sensitive of the inspection methods. However, frequent tests, i.e., monthly, would be required to substantially reduce leakage. A risk reduction factor of 0.1 was assessed for such frequent inspections. This method would be particularly beneficial in certain high risk areas where even minute spills can be hazardous. The pressure static method, by itself, would not appreciably reduce leak spill volume because of its poor sensitivity. However, after a medium sized leak is indicated by some other means, this method is effective in verifying the existence of a leak. It was assessed a risk reduction factor of 0.8 assuming it would be used in conjunction with mathematical modeling or the passive acoustic array. Hydrostatic tests carried out even on a frequent basis are not expected to substantially reduce the

EPA Form 2350-4 (4-80)

TYPING GUIDE SHEET

leak spill volume. The method, however, would be quite effective in verifying the existence of small to medium sized leaks. Risk reduction factors of 0.6 and 0.7 were assessed for the two inspection schedules given in Table 67.

Combinations of leak detection and inspection methods are capable of affecting improved reduction in the risk. A few of the more effective combinations are shown in Table 67.

Only a few methods appear to be highly effective in reducing the volume of leak type spills. Of all the methods, the pressure difference methods appear to be the most effective. However, this inspection method requires installation of closely spaced block valves and also requires line shutdown during the inspection. Frequent visual and visual-aided line inspections appear to be highly effective methods in reducing the volume of these oil spills. However, almost daily inspections are required to produce risk reduction factors better than 0.5. Twice yearly hydrostatic tests with the passive acoustic array are judged to be effective. The main reason is that the acoustic array can be used to locate the leaks. This is particularly important during hydrostatic tests on long lines where a number of small leaks may be erroneously accounted for by temperature or other effects. Hydrocarbon probes may be substituted for the acoustic array if the line is filled with petroleum or gas detectors or analyzers may be substituted if the line is pressurized with helium of some other inert gas.

Since only about ten percent of the spill volume is attributed to leak-type spills, no method presented can affect a significant reduction in the spill volume as compared to the methods identified for rupture type spills. Because even leak type spills can be serious, particularly in high risk areas, the volume of these spills should be reduced as much as possible.

7.1.2.2 Factors Affecting the Capability of Methods to Reduce the Frequency of Spills--

The capability of a method to reduce and, if possible, eliminate the occurrence of spills depends upon the ability of the method to detect impending failures (internal defects) sufficiently early so that pipe line repairs can be made and a spill prevented. Various methods can be implemented to detect pipeline defects that may result in a spill. The following three main factors affect the capability of these leak detection and inspection methods detect impending failure and thereby reduce the frequency of spills:

- Sensitivity (detectable defect size)
- Location accuracy (pinpointing defect)
- Frequency of inspection.

The effect of each of these factors varies widely depending upon the implementation of each method. It also depends upon whether the method is used for reducing the frequency of leaks or ruptures or the frequency of spills by cause. Thus the combined effects of these characteristics along with risk reduction factors[a] and normalized values[b] for risk reduction. In the analysis, risk reduction is based on the capability of an individual method or combination of methods to reduce the oil spill risk below the value estimated for the methods in common use on most lines for the reference year 1975. Inspection and leak detection methods for operational lines that are assumed in the analysis for the reference year are:

- Biweekly visual inspections by air or ground patrol for indications of a spill--(Required by U.S. regulations)
- Periodic inspections of the cathodic protection system--(Required by U.S. regulations)
- Monitoring of line pipe pressure deviations at pump stations
- Voluntary One-Call System.

To simplify comparisons of the selected methods, a normalized risk reduction value is provided. This allows one to compare the number of inspections by various methods to achieve a certain reduction in the oil spill risk. The normalized value is based on a single reference inspection. One visual inspection in excess of the bimonthly inspections by air or ground patrol is used for this purpose. Results indicate, for example, that one inspection by an inspection survey pig is equivalent to 136 visual inspections of the line for reducing the frequency of leaks by 52 percent.

7.1.2.1 Factors Affecting the Capability of Methods to Reduce the Volume of Spills--

Rapid detection and location of the onset of small quantities of petroleum pipeline leakage so that system shutdown can be initiated are the four most important factors in reducing the volume of accidental spills. The four major factors (method characteristics or specifications) for reducing the volume of spill are specifically:

- Response time
- Leak location accuracy
- Leak sensitivity
- Frequency of inspection.

---

[a] Risk of oil spills, after applying the inspection method, is the product of this factor and the risk value with currently required commonly used inspections. The value is obtained by subtracting the percent reduction from 1.00.

[b] Risk reduction normalized is the value of the percent reduction of the spill risk for a single inspection divided by the percent reduction of the spill risk for one reference inspection.

these other considerations determine the overall capability of a method to reduce the frequency of spills. Hence, each is considered in the evaluation. Section 7.1.2.1 provides a discussion of the significance of these factors.

Implementation of leak detection and inspection methods that are capable of satisfying these required characteristics is considered to be the optimum approach for minimizing the hazards of accidental spills from petroleum line pipe. In general, prevention of ruptures would normally be of higher priority than the prevention of leaks. However, the objective should be to reduce all spill incidents. At this time, U.S. regulations for installation and periodic inspections of cathodic protection systems in the line pipe and depth of cover on line pipe are the main U.S. efforts in achieving reduction of frequency of spills. Although these methods are quite useful, they have not resulted in significant reductions in the frequency of spills, particularly those resulting in "rupture-type" spills. The major emphasis in a spill prevention and control program should be directed towards the goal of eliminating or at least minimizing the frequency of spills. The reason for this conclusion is that methods that reduce the volume of spills (detect actual spills) do not stop spills. These methods have two inherent limitations. First, even with rapid detection of medium to large size spills, a certain amount of hazardous fluid can escape from the line before the spill is totally contained. Secondly, many "leak-type" spills and many "rupture-type" spills cannot be detected.

The sensitivity of the method is the most important capability in reducing the frequency of spills. Sensitivity is based on the ability of the method to detect minute internal defects that may lead to a leak or minutely small leaks (drip type) that may lead to failure.

The frequency of inspection is also an important consideration. For example, increased frequency of visual inspection of the line for the purpose of eliminating third party activities such as excavations that might result in damage to the line pipe, reduces the risk of a line pipe spill.

The capability of providing accurate leak location, i.e., within a few feet is also important. For example, the ability to pinpoint a small leak during hydrostatic tests greatly enhances the effectiveness of a method.

It is difficult to assess quantitatively the ability of a method to reduce the frequency of spills, for a number of reasons. These include:

- The geometry and dimensions of an interval defect that will result in a spill incident are not precisely known.
- The geometry and dimensions of leaking areas are not reportable. Thus, information as to minimum or typical hole size that would result in a leak or rupture type spill is not precisely known.
- Quantitative data suitable for detailed comparisons of many of the selected methods are not available.

- Effectiveness of some inspection methods often depend upon such factors as line pipe dimensions (i.e., diameter) and location (i.e., onland, underwater, etc.).

Nevertheless, sufficient information is available from manufacturers and user experience (see Tables through and Appendix E) to make qualitative estimates that are suitable for analysis.

For typical lines, the capability of a method to reduce the frequency of spills by cause is of prime importance. For certain line pipe, analysis of the capability of a method to reduce incidents of spills based on type, leak or rupture, can be particularly advantageous. For example, older lines typically have high potential for leaks whereas large diameter new lines have an inordinately high potential for ruptures.

Analysis of the reduction of the frequency of spills is carried out in the subsections that follow. Analysis by cause and type (leaks, rupture) are treated separately.

7.1.2.2.1 Estimation of Capability of Reducing Spill Incidents from All Causes Using Selected Methods

Selected leak detection and inspection methods for reducing the frequency of spill incidents for each of the major causes of spills and all causes combined are presented in Table 68. Methods are shown along with frequency of inspection, percent reduction of incidents, risk reduction factors and normalized values for risk reduction. A single inspection in excess of the required bimonthly visual inspections is the reference inspection. It is used in the computation of the normalized values for risk reduction. Biweekly visual line inspections and periodic monitoring of the cathodic protection system are assumed to be the commonly used methods during the reference year for spill prevention.

Capability to prevent line pipe faults is based primarily upon the overall ability of a method to detect insignificant leaks or line pipe defects that are generally indicative of impending failure. Capability to prevent damage by outside forces is based on the overall ability of a method to detect activities of outside forces (usually impacts) before a failure can occur.

The number of incidents for the causes of line pipe failures were obtained from Table 19. These are:

- Line pipe faults - 56 percent of spills
- Outside forces - 41 percent of spills
- Other causes - 3 percent of spills.

These values are used in the computation of the percent reduction of spill incidents identified under all causes. For example, a method that accounts for a 50 percent reduction of spills from the line pipe faults but no other reductions would account for a 28 percent reduction in the overall causes of spills.

TABLE 68. REDUCTION ANALYSIS FOR THE FREQUENCY OF OIL SPILLS BY CAUSE FOR A TYPICAL SECTION OF LINE PIPE (REFERENCE LINE)

Inspection or Leak Detection Method	Inspections Frequency/ Year	% Reduction of Oil Spill Incidents[1,2]					Risk Reduction Factor[4]	Risk Reduction Normalized[5]
		Line Pipe Faults	Outside Forces	Other Causes	All Causes			
		(56% of Spills)	(40% of Spills)	(3 % of Spills)	Indicated Inspections	Single Inspection		
1. Visual inspection by air or ground patrol (Required inspections)	26	0	0	0	0	0	NA	NA
2. Visual inspection by air or ground patrol in excess of required inspections	a. 26 (Ref) b. 338	5 10	28 80	IND IND	11 38	0.42(Ref) 0.11	0.89 0.62	1.0 (Ref) 0.3
3. Visual inspection by ground patrol with hydrocarbon detector or other comparable device	a. 26(Req.) b. 52 c. 338	30 35 40	IND 20 80	IND IND IND	16 28 55.	3.2 1.06 0.16	0.84 0.72 0.45	7.62 2.52 0.38
4. Hydrocarbon probe-towfish or similar device - Underwater lines only - All lines	6 6	50 5	IND IND	IND IND	28 2.8	4.7 0.47	0.72 0.97	11.2 1.2
5. Depth of cover inspection by sonar (sidescan and penetrating) or other comparable device - Underwater lines only - All lines	4 4	IND IND	80 10	0 0	32 4.1	8 1	0.68 0.96	19 2.4
6. Charting of line pipe - Underwater lines only - All lines	1 1	IND IND	IND IND	IND IND	8.4 IND	8.4 IND	0.9 IND	20 IND
7. Passive acoustic array	a. cont.[6] b. cont.[7]	IND 10	70 90	IND IND	28 43	28 43	0.72 0.57	67 107
8. Hydrostatic	a. 1 b. 2	50 60	IND IND	IND IND	28 34	28 34	0.72 0.66	57 40
9. Pressure difference	a. 1 b. 4	70 90	IND IND	IND IND	39 50	39 12.5	0.61 0.50	93 46
10. Change or add inhibitors as needed	3[8]	10	IND	IND	5.6	1.9	0.95	4.5
11. Inspection of sample of line for wall thickness by ultrasonic or comparable technique	1	20	IND	IND	11	11	0.89	26
12. Survey by inspection pig-magnetic flux type or other comparable device	a. 0.25 b. 0.50 c. 1	66 75 85	IND IND IND	IND IND IND	37 42 47	37 42 47	0.63 0.58 0.53	88 100 112
13. Pig line for water removal	3[8]	10	IND	IND	5.6	1.9	0.95	4.5
14. Preventive program for outside forces (Reference 12) One-Call System	cont.	10	60	IND	30	30	0.70	71
15. 7(b) and 8	1	80	90	IND	82	82	0.18	195
16. 12(c) and 14	1	90	90	IND	87	0.87	0.13	207
17. 3(a), 12(c), 14	26	95	95	IND	92	3.54	0.08	8.43

Notes:
(1) NA - Not applicable since method was commonly used when spill frequencies were determined.
(2) IND - Improvement not discernable.
(3) Reduction of spill incidents, after applying inspection and/or leak detection method is the sum of the products of the reduction factors and the percentage of spills resulting from cash cause (line pipe - 56%, outside forces 41%, other 3%) for the reference line.
(4) Risk of spills, after applying the inspection method is the product of this factor and the risk value with current required and commonly used inspections, the value is obtained by subtracting the % reduction from 1.0.
(5) Risk normalized is the percent reduction from a single inspection divided by the percent reduction resulting from one reference inspection..
(6) Retrofit installation.
(7) New line installation.
(8) Assume frequency of inspection carried out three times a year.

Biweekly visual inspections carried out by air or ground patrol are considered ineffective in preventing spills, even spills caused by outside forces. Analysis of spill statistics (see Figure 22) indicates little or no change in the reported incidents by outside forces, such as equipment rupturing the line, between 1970 and 1976. Spill prevention by this inspection method is considered to be minimal.

Periodic inspections of cathodic protection systems are considered to be responsible for some reduction in the spill incidents from external corrosion. Data such as presented in Figure 22 indicate substantial reduction in external corrosion between 1970 and 1976. Some of this reduction can be attributed to cathodic protection systems. It should be noted, however, that external corrosion generally results in the smallest spill size for the major causes of spills (see Table 19). Thus, a significant reduction in external corrosion does not affect a significant reduction in the total volume of petroleum spilled. Also, these cathodic protection systems are ineffective for reducing the incidence of internal corrosion and other major causes of spills.

Visual inspections by air or ground patrol carried out on a weekly basis are expected to reduce incidents of damage by outside forces by about 20 percent and line pipe faults by about five percent. For these 26 additional inspections, a risk reduction factor of 0.9 was assessed. For daily inspections, a risk reduction factor of 0.6 was assessed.

Use of visual aids, such as hydrocarbon probes or other comparable devices, by ground patrol is expected to improve the detection of insignificantly small leaks that may result in a reportable spill. Respective risk reduction factors of 0.84, 0.72 and 0.45 were assessed for aided inspections by ground patrol that are carried out biweekly, weekly and daily.

Bimonthly inspections of underwater lines using hydrocarbon probes or other equivalent devices in a towfish system that traverses the line is expected to be quite effective in detecting and locating small leaks that occur from corrosion and weld defects. These inspections are expected to detect very small leaks that may lead to failure and that could not be detected by other means. A risk reduction factor of 0.72 is assessed for underwater lines, and a factor of 0.97 when all line pipe mileage is included. Visual inspections at the surface for underwater lines are considered to provide no discernible prevention of line pipe faults.

Quarterly inspections of the line pipe for the depth of cover may reduce significantly the frequency of ruptures. Since most undersea pipeline ruptures are caused by external impacts such as anchor dragging, a proper depth of cover will minimize the potential of damage from these sources. These inspections are judged to reduce the incidents of spills from outside forces by about 80 percent. The overall risk reduction factor is 0.68. For all line pipe, these surveys were judged to have a risk reduction factor of only 0.97.

EPA Form 2250-4 (4-80)
TYPING GUIDE SHEET

Charting the movements underwater lines enables one to detect abnormal movements which could excessively stress the line. Inspections every two years were judged to reduce the incidents of line pipe faults by about 15 percent; a risk reduction factor of 0.91 was assessed for underwater lines and negligible risk reduction factor when all lines are included.

Use of a continuous monitoring passive acoustic array is expected to be highly effective in reducing the incidents of damage by outside forces and slightly effective in detecting impending line pipe failures, primarily ruptures. A risk reduction factor of 0.57 was assessed for this method.

Yearly hydrostatic tests of the line pipe were judged to be capable of detecting a majority of serious line pipe faults, i.e., minute leaks. For this method, an overall risk reduction factor of 0.66 was assessed. If used with the acoustic array, a much greater effectiveness can be achieved since the line pipe response to changes in stress levels can be monitored. The risk reduction factor of 0.18 is assessed for the combined methods.

Periodic pressure difference tests are judged to be the most effective inspection method for detecting small leaks that may lead to failure. For inspections carried out yearly and quarterly, risk reduction factors were assessed at 0.61 and 0.50, respectively.

Yearly inspections of the condition of the interior of the line pipe using inspection pigs are considered to be the best method overall for detecting line pipe faults. Commercially available devices, such as equipment from AMF Tuboscope, Inc. and Vetco, Inc. can be used in lines ranging from six to 36 inches in diameter. A risk reduction factor of 0.53 was assessed for yearly inspections with this device.

The prevention program for outside forces, the One-Call System, as recommended in Reference 12, is considered to have the potential of significantly reducing the damage by outside forces. An overall risk reduction factor of 0.70 was assessed for this program.

Pigging the line for water removal is an important inspection/maintenance activity that should be carried out on a frequent basis. This method reduces the risk of internal corrosion and other causes of line pipe spills. Since the method is often used on many lines, it has affected some reduction in the spill risk. Thus, a risk reduction factor of only 0.95 was assessed.

Inspections of sample sections of the line for wall thickness changes caused by corrosion can be effective in reducing the risk of oil spill incidents, particularly for lines with corrosion problems. It is only practical to sample a small area of a line. This small sampling is judged to be inadequate and thus no significant reduction in the risk can be attained; a risk reduction factor of only 0.89 was assessed.

Combinations of leak detection and inspection methods are capable of significantly reducing the risk of spill incidents. A few of the more effective combinations are shown in Table 28. Pigging the line for prevention of line pipe faults used in conjunction with a One-Call System program to prevent outside forces is expected to produce an excellent risk reduction factor of 0.13. If weekly visual inspections added by the use of hydrocarbon probes are also carried out, the risk reduction factor further improves to 0.08.

7.1.4.2.2 Estimation of the Capability of Reducing the Frequency of Leaks Using Selected Methods

Results of a reduction analysis for the prevention of "leak type" spills are given in Table 69. Selected methods and major causes of spills are the same as in the previous section. However, the values indicated in the table are specifically for the reduction of "leak type" spills. These values have been based on two estimates[a]. First, "leak type" spills are considered to account for 75 percent of the reported accidental spills. Second, the major causes of spills are expected to account for the following incidents of leaks:

LEAKS (75 percent of all spills)

- Line pipe faults - 61 percent of leaks (46 percent of all spills)
  - corrosion - 52 percent of leaks (39 percent of all spills)
  - defective pipe seams, welds, etc. - 9 percent of all leaks (7 percent of all spills)
- Outside forces - 35 percent of leaks (26 percent of all spills)
  - equipment rupturing line - 28 percent of all leaks (21 percent of all spills)
  - miscellaneous - 7 percent of leaks (5 percent of all spills)
- Other - 4 percent of leaks (3 percent of all spills).

Only a few methods appear to have the potential of significantly reducing the line pipe faults which account for most (over 61 percent) of the incidents of leaks. One method, survey by inspection pig, appears to be the most promising. Other methods judged to have the potential of significantly reducing line pipe faults include:

- Hydrocarbon probe with towfish for underwater lines
- Hydrostatic pressure testing
- Pressure difference pressure testing.

In preventing damage by outside forces, only these methods appear to be effective. These include:

- Acoustic array
- Depth of cover inspection of underwater lines
- Frequent, e.g., daily, visual inspections of the line
- Prevention program for outside forces--One-Call System.

---

[a] These are rough estimates and suitable for the evaluation purposes in this study only.

TABLE 69. SPILL REDUCTION ANALYSIS FOR THE FREQUENCY OF LEAKS FOR A TYPICAL SECTION OF LINE PIPE

Inspection or Leak Detection Method	Inspections Frequency/ Year	% Reduction of Leak Incidents[1,2]					Risk Reduction Factor[4] (RRF_{FL})	Risk Reduction Normalized[5]
		Line Pipe Faults (61% of leaks)	Outside Forces (35% of leaks)	Other Causes (4% of leaks)	All Causes[3]			All Causes Single Inspection
					Indicated Inspections	Single Inspection		
1. Visual inspection by air or ground patrol (Required inspections)	26	0	0	0	0	0	NA	NA
2. Visual inspection by air or ground patrol in excess of required inspections	a. 26(Ref) b. 338	5 10	20 80	IND IND	10 34.1	0.38(Ref) 0.10	0.90 0.66	1.0(Ref) 0.3
3. Visual inspection by ground patrol with hydrocarbon detector or other comparable device	a. 26(Ref) b. 52 c. 338	30 35 40	IND 20 80	IND IND IND	18.3 28.3 45	3.66 1.04 0.13	0.82 0.72 0.55	9.63 2.87 0.34
4. Hydrocarbon probe-towfish or similar device								
- Underwater lines only	6	50	IND	IND	30.5	5.08	0.70	13.4
- All lines	6	5	IND	IND	3.0	.51	0.97	1.3
5. Depth of cover inspection by sonar (sidescan and penetrating) or other comparable device								
- Underwater lines only	4	IND	80	0	28	7	0.72	18.4
- All lines	4	IND	10	0	2.8	.7	0.97	1.8
6. Charting of line pipe								
- Underwater lines only	1	15	IND	IND	9.2	9.2	0.91	24.2
- All lines	1	IND	IND	IND	IND	IND	IND	IND
7. Passive acoustic array	a. cont.[6] b. cont.[7]	IND 10	60 90	IND IND	21.5 37.6	21.5 37.6	0.79 0.62	57 99
8. Hydrostatic	1 7	50 60	IND IND	IND IND	30.5 36.6	30.5 18.3	0.70 0.63	70.6 48.6
9. Pressure difference	1 4	70 90	IND IND	IND IND	42.7 67.8	42.7 17	0.57 0.32	112 44.7
10. Change or add inhibitors as needed	3[8]	10	IND	IND	6.1	2.03	0.94	5.34
11. Inspection of sample of line for wall thickness by ultrasonic or comparable technique	1	20	IND	IND	12.2	12.2	0.88	32.1
12. Survey by inspection pig-magnetic flux type or other comparable device	a. 0.25 b. 0.50 c. 1	66 75 85	IND IND IND	IND IND IND	40.3 45.8 51.8	40.3 45.8 51.8	0.60 0.54 0.48	106 120 136
13. Pig line for water removal	3[8]	10	IND	IND	6.1	2.03	0.94	5.3
14. Preventive program for outside forces (Reference 12) One-Call System	cont.	10	60	IND	27.1	27.1	0.73	71.3
15. 7(b) and 8	1	80	90	IND	80.3	80.3	0.20	211
16. 12(c) and 14	1	90	90	IND	86.4	86.4	0.14	227
17. 3(a), 12(c), and 14	26	95	95	IND	91.2	3.51	0.09	9.2
18. 7(b) and 12(c)		90	90	IND	86.4	86.4	0.14	227

Notes:
(1) NA - Not applicable since method was commonly used when spill frequencies were determined.
(2) IND - Improvement not discernable.
(3) Reduction of spill incidents, after applying inspection and/or leak detection method is the sum of the products of the reduction factors and the percentage of spills resulting from cash cause (line pipe - 61%, outside forces 35%, other 4%) for the reference line.
(4) Risk of spills, after applying the inspection method is the product of this factor and the risk value with current required and commonly used inspections, the value is obtained by subtracting the % reduction from 1.0.
(5) Risk normalized is the percent reduction from a single inspection divided by the percent reduction resulting from one reference inspection..
(6) **Retrofit installation**
(7) **New line installation.**
(8) **Assume frequency of inspection carried out three times a year.**

These methods are most effective in reducing either line pipe faults or outside incidents. Hence, no individual method appears to have the potential of eliminating most of the leak type spills. Only two methods are judged to have risk reduction factors better than 0.5. Bi-yearly surveys by inspection pigs are assessed at slightly better than 0.5. Frequent pressure difference tests are assessed at 0.32. By using combinations of inspections, however, risk reduction factors of better than 0.20 are potentially possible. For example, using the survey inspection pig and either a prevention program for outside force or a passive acoustic array system are assessed excellent risk reduction factors of 0.14.

Based on normalized risk reduction factors and single inspections, five methods stand out for reducing risks. These include:

- Survey by inspection pigs
- Pressure difference
- Passive acoustic array
- Hydrostatic
- Prevention program for outside forces One-Call System.

7.1.4.2.3 Estimation of the Capability of Reducing the Frequency of Ruptures Using Selected Methods

Results of reduction analysis for the prevention of "rupture type" spills are given in Table 70. Selected methods and major causes of spills are the same as those identified in Section 7.1.4.2.1. Values indicated in the table are computed using the same approach followed in the reduction analysis of the frequency of "leak type" spills. "Rupture type" spills are estimated to account for 25 percent of the reported accidental spills. The major causes of spills are estimated to account for the following incidents of rupture:

RUPTURES (25 percent of all spills)

- Line pipe faults - 40 percent of ruptures (10 percent of all spills)
  - defective line pipe - 40 percent of ruptures (10 percent of all spills)
- Outside forces - 60 percent of ruptures (15 percent of all spills)
  - Equipment rupturing line - 40 percent of ruptures (10 percent of all spills)
  - Excavation equipment - 12 percent of ruptures (3 percent of all spills)
  - Miscellaneous - 8 percent of ruptures (2 percent of all spills).

BEGIN FIRST LINE OF TEXT HERE
CENTER OF PAGE
TOP OF IMAGE AREA
DROPPED HEAD BEGIN SECTIONS HERE

TABLE 70. SPILL REDUCTION ANALYSIS FOR THE FREQUENCY OF RUPTURES FOR A TYPICAL SECTION OF LINE PIPE

Inspection or Leak Detection Method	Inspections Frequency/ Year	% Reduction of Rupture Incidents (1), (2)					Risk Reduction Factor(4) (RRF$_{FR}$)	Risk Reduction Normalized(5)
		Line Pipe Faults (40% of ruptures)	Outside Forces (60% of ruptures)	Other Causes (negligible)	All Causes(3) Indicated Inspections	All Causes(3) Single Inspection		All Causes Single Inspection
1. Visual inspection by air or ground patrol (Required inspections)	26	0	0	0	0	0	NA	NA
2. Visual inspection by air or ground patrol in excess of required inspections	26(Ref) 338	5 10	20 80	IND IND	14 52	0.54(Ref) 0.15	0.86 0.48	1.0(Ref) 0.28
3. Visual inspection by ground patrol with hydrocarbon detector or other comparable device	26(Req) 52 338	30 35 40	IND 20 80	IND IND IND	12 (7) 26 64	2.4 1.0 0.36	0.88 0.74 0.36	4.44 1.85 0.4
4. Hydrocarbon probe-towfish or similar device - Underwater lines only - All lines	6 6	50 5	IND IND	IND IND	20 2	3.33 .33	0.80 0.99	6.17 .61
5. Depth of cover inspection by sonar (sidescan and penetrating) or other comparable device - Underwater lines only - All lines	4 4	IND IND	80 10	0 0	48 6	12 1.5	0.52 0.94	22.2 2.8
6. Charting of line pipe - Underwater lines only - All lines	1 1	15 IND	IND IND	IND IND	6 IND	6 IND	0.94 IND	11.1 IND
7. Passive acoustic array	a. cont.(6) b. cont.(7)	IND 10	60 90	IND IND	36 58	36 58	0.64 0.42	66 107
8. Hydrostatic	1 2	50 60	IND IND	IND IND	20 24	20 12	0.80 0.76	37 22.2
9. Pressure difference	1 4	70 90	IND IND	IND IND	28 36	28 9	0.72 0.64	52 16.7
10. Change or add inhibitors as needed	3(6)	10	IND	IND	4	1.35	0.96	2.3
11. Inspection of sample of line for wall thickness by ultrasonic or comparable technique	1	20	IND	IND	8	8	0.92	14.8
12. Survey by inspection pig-magnetic flux type or other comparable device	0.25 0.50 1.00	66 75 85	IND IND IND	IND IND IND	26 30 34	26 30 34	0.74 0.70 0.66	48 55 63
13. Pig line for water removal	3(8)	10	IND	IND	4	1.35	0.96	2.3
14. Preventive program for outside forces (Reference 12) One-Call System		10	60	IND	40	40	0.60	74
15. 7(b) and 8	1	80	90	IND	86	86	0.14	159
16. 12(c) and 14	1	90	90	IND	90	90	0.10	167
17. 3(a), 12(c) and 14	26	95	95	IND	95	3.65	0.05	6.8

Notes:
(1) NA - Not applicable since method was commonly used when spill frequencies were determined.
(2) IND - Improvement not discernable.
(3) Reduction of spill incidents, after applying inspection and/or leak detection method is the sum of the products of the reduction factors and the percentage of spills resulting from cash cause (line pipe - 40%, outside forces 60%, other negligible) for the reference line.
(4) Risk of spills, after applying the inspection method is the product of this factor and the risk value with current required and commonly used inspections, the value is obtained by subtracting the % reduction from 1.0.
(5) Risk normalized is the percent reduction from a single inspection divided by the percent reduction resulting from one reference inspection.
(6) Retrofitt installation
(7) New installation
(8) Assumes frequency of inspection carried out three times a year.
(9) Inspection estimated to add 20 percent to the inspection time or the equivalent of five inspections.

BEGIN LAST LINE OF TEXT

TYPING GUIDE SHEET

Methods that appear most promising for reducing line pipe faults and outside forces for "rupture type" spills are similar to those previously identified for "leak type" spills. Whereas line pipe faults account for most leak incidents, outside forces are the major causes of ruptures. Thus, there are some differences in the risk reduction factors and normalized risk values for the most effective methods for "rupture type" spills. Two methods judged to have risk reduction factors better than 0.5 are:

- Frequent, e.g., daily, visual inspections by ground patrol with hydrocarbon detectors or other comparable devices
- Passive acoustic array.

By using a combination of inspections, risk reduction factors of better than 0.20 are potentially possible.

7.2 OIL SPILLAGE THAT POTENTIALLY CAN BE PREVENTED USING THE SELECTED LEAK DETECTION AND INSPECTION METHODS

Analysis of the spillage that potentially can be prevented (or go undetected) by implementation of the selected inspection and leak detection methods is carried out in this section. From this analysis, it is possible to estimate the expected reduction of spill incidents and spill volume for a scheduled series of inspections. Estimates are based on the results of the analysis of the oil spill risks in Section 6.3 and the capabilities of selected methods to reduce the oil spill risks in Section 7.1.2.

The approach and necessary equations for estimating spillage are presented in Section 7.2.1. Sufficient information is provided so that quantitative values can be determined for most lines.

Values for spillage prevented using selected leak detection and inspection methods are computed and results discussed for the reference line in Section 7.2.2. Spillage values are computed for all U.S. lines in Section 7.2.3.

7.2.1 Means of Calculating Spillage that Potentially can be Prevented

Quantitative values of the spillage that potentially can be prevented (or go undetected) can be computed for most lines using the equations provided in Sections 7.2.1.2 through 7.2.1.4. The frequency and volume of spillage can be estimated for all spills and also for "leak type" and "rupture type" spills. Values for existing spillage that must be used in these equations can be obtained from information provided in Section 7.2.1.1. The risk factors for the various leak detection and inspection methods that also must be used in these equations can be obtained in Table 71[a].

---

[a] This table summarized the risk reduction factors from Tables 65, 67, 69 and 70.

TABLE 71. SUMMARY OF RISK REDUCTION FACTORS FOR SELECTED INSPECTION AND LEAK METHODS

Inspection and/or Leak Detection Methods	Inspections Frequency/ Year	Oil Spill Risk Reduction Factors[1,2,3]			
		Frequency		Volume	
		Leaks RRF_{FL}	Ruptures RRF_{FR}	Leaks RRF_{VL}	Ruptures RRF_{VR}
1. Visual inspection of line by air or ground patrol (required inspections) for indication of spill	26	1	1	1	1
2. Visual inspection of line by air or ground patrol in excess of required inspections for indication of spill	26(Ref)	0.90	0.86	0.70	0.95
	338	0.66	0.48	0.30	0.60
3. Visual inspection of line by ground patrol with hydrocarbon probe or comparable device for indication of spill	a. 26(Reg)	0.82	0.88	0.80	0.98
	b. 52	0.72	0.74	0.60	0.95
	c. 338	0.55	0.36	0.20	0.60
4. Hydrocarbon probe-towfish or similar device					
-Underwater lines only	6	0.70	0.80	0.50	0.70
-All lines	6	0.97	0.99	0.95	ind
5. Pressure deviations					
a. Pump stations (existing method)	continuous	NS	NS	NA	NA
b. Along line	continuous	NS	NS	NS	0.90
6. Flow Rate					
a. Deviations	continuous	NS	NS	NS	0.80
b. Comparisons (computerized)	continuous	NS	NS	NS	0.60
7. Volume comparisons(computerized)	continuous	NS	NS	ind	0.30
8. Mathematical modeling (computerized)	continuous	NS	NS	0.80	0.10
9. Negative pressure surge (computerized	continuous	NS	NS	NS	0.70
10. Passive acoustic array (computerized)	a. continuous[4]	0.79	0.66	IND	0.40
	b. continuous[5]	0.62	0.42	0.80	0.30
11. External rods with passive acoustic sensors		NS	NS	0.90	0.90
12. Pressure static	after indication of spill[3]	NS	NS	0.80	0.80
13. Hydrostatic	a. 1	0.70	0.80	IND	IND
	b. after indication of spill[6]	0.63	0.70	0.70	NS
	c. 2	0.68	0.76	0.60	NS
14. Pressure difference	a. 1	0.57	0.72	0.70	NS
	b. 2	0.50	0.68	0.50	NS
	c. 4	0.32	0.64	0.40	NS
	d. 12	0.30	0.60	0.10	NS
15. Change or add inhibitors as needed	3	0.94	0.96	NS	NS
16. Inspection of sample of line for wall thickness by ultrasonic or comparable technique	1	0.88	0.92	NS	NS
17. Survey by inspection pig-magnetic flux type or other comparable device	a. 0.25	0.60	0.74	NS	NS
	b. 0.50	0.54	0.70	NS	NS
	c. 1	0.48	0.66	NS	NS
18. Depth of cover inspection by sonar (sidescan and penetrating) or other comparable device					
-Underwater lines only	4	0.72	0.52	NS	NS
-All lines	4	0.97	0.94	NS	NS
19. Charting of line pipe					
-Underwater lines only	0.5	0.91	0.94	NS	NS
-All lines	0.5	IND	IND	NS	NS

(continued)

TABLE 71 (continued)

Inspection and/or Leak Detection Methods	Inspections Frequency/ Year	Oil Spill Risk Reduction Factors[1,2,3]			
		Frequency		Volume	
		Leaks RRF_{FL}	Ruptures RRF_{FR}	Leaks RRF_{VL}	Ruptures RRF_{VR}
20. Preventive program for outside forces (Reference 12)	cont.	0.73	0.60	NS	NS
21. Pig line for water removal	3[6]	0.94	0.96	NS	NS
22. Oil spill detectors					
-Marine terminal or platform	continuous	IND	NS	0,50	NS
-Total line pipe mileage	continuous	IND	NS	0.95	NS
23. 10(b) and 13(a)		0.20	0.14	0.50	0.70
24. 17(c) and 20		0.14	0.10	NS	NS
25. 3(a), 17(c) and 20		0.09	0.05	0.60	0.95
26. 10(b) and 17(c)		0.10	0.14	0.80	0.30
27. 5(a), 6(a), 7		0	0	IND	0.20
28. 5(a), 6(a), 6 (b), 7 and 9		0	0	IND	0.05
29. 8 and 17(c)		0.48	0.66	0.80	0.10

Notes:

(1) NA - Not applicable since method was commonly used for year when risks were determined.

(2) NS - Not suitable for indicated detection of leaks or ruptures. Therefore a risk reduction factor of 1 is assigned.

(3) IND - Improvement not discernible. Therefore a risk reduction factor of 1 is assigned.

(4) Retrofit installation.

(5) Installation of new lines.

(6) Assume frequency of inspection carried out three times a year.

Particular attention should be given to the means of computing the total volume of spills (Section 7.2.1.4) that can be prevented. Total volume depends on the capabilities of a particular method to reduce both parts of the risk, i.e., preventing spills and reducing the size of each spill. This results in more complex equations than required in computing spillage for methods that reduce only one part of the risk.

7.2.1.1 Computation of Existing Annual Spillage--Frequency, Volume and Spill Size--

The oil spill risk, total volume spilled V_{STC} and frequency F_{STC}, is computed for the line using an approach similar to the one presented in Section 6.3.4. First, the spill risk for the reference line, frequency F_{ST} and volume V_{ST}, are obtained from Table 57. Then values for correction factors which are used to account for variations from the reference line are obtained. Correction factors for the frequency CF_F (age, geometry, length, use, spill size) and volume CF_{VM} (diameter, length, use, pumping station shutdown, mainline valve closure, line elevation) are estimated using Figures 54 and 57. Annual volume V_{STC} and frequency F_{STC} of spills from the line are then calculated using Table 59.

The same approach can be used in computing the nominal largest spill size for ruptures V_{NLRC}, leaks V_{NLLC} and mean spill size V_{MC}. Table 60, however, is used instead of Table 59.

7.2.1.2 Computation for Reducing the Frequency of Spills--

The number of spills that can be prevented (or go undetected) can be computed for the methods installed specifically for the reduction of oil spill incidents. This can be done since the oil spill risk F_{STC} and the risk reduction factors, RRF_{FL} and RRF_{FR}, for the methods are known. Assuming 75 percent of the spills can be attributed to "leakage-type" and the remainder to "rupture type," the following can be used to estimate annual frequency of spills:

$$F_{LP} = (0.75 \times F_{STC})\ (1 - RRF_{FL}) \tag{1}$$

$$F_{RP} = (0.25 \times F_{STC})\ (1 - RRF_{FR}) \tag{2}$$

$$F_{P} = F_{LP} + F_{RP} \tag{3}$$

$$F_{U} = F_{LP} - F_{RP} + R_{STC} \tag{4}$$

where

F_{STC} = total frequency of spills corrected for line pipe

F_{LP} = frequency of leaks prevented after installation of leak detection and/or inspection method(s)

F_{RP} = frequency of rupture prevented after installation of leak detection and/or inspection method(s)

F_P = total frequency of spills prevented after installation of leak detection and/or inspection method(s)

RRF_{FL} = risk reduction factor for frequency of leaks after installation of leak detection and/or inspection method(s) - see Table 71

RRF_{FR} = risk reduction factor for frequency of ruptures after installation of leak detection and/or inspection installed - see Table 71

F_U = total frequency of spills undetected after installation of leak detection and inspection method(s).

7.2.1.3 Computation of the Reduction of the Volume of Spills Using Methods that Reduce Only the Spill Size--

The value of volume of spills that can be prevented or go undetected can be computed for the methods installed specifically for spill size reduction. This can be done since the oil spill risk for the volume spilled V_{STC} and the risk reduction factors, RRF_{VF} and RRF_{VL}, for the methods are known. Assuming that 90 percent of the spill volume can be attributed to "rupture-type" and the remainder to "leak-type," the following can be used to estimate annual volume of spills:

$$V_{LP} = 0.10\ V_{STC}\ (1 - RRF_{VL}) \qquad (5)$$

$$V_{RP} = 0.90\ V_{STC}\ (1 - RRF_{VR}) \qquad (6)$$

$$V_P = V_{LP} + V_{RP} \qquad (7)$$

$$V_U = V_{LP} = V_{RP} + V_{STC} \qquad (8)$$

where

V_{STC} = total volume of spills corrected for line pipe

V_{LP} = volume of leaks prevented after installation of leak detection and/or inspection method(s)

V_{RP} = volume of ruptures prevented after installation of leak detection and/or inspection method(s)

RRF_{VL} = risk reduction factor for volume of leaks after installation of leak detection and/or inspection method(s) - see Table 71

RRF_{VR} = risk reduction factor for volume of rupture after installation of leak detection and/or inspection method(s) - see Table 71

V_P = volume of spills prevented after installation of leak detection and/or inspection method(s)

V_U = volume of spills undetected after installation of leak detection and/or inspection method(s).

7.2.1.4 Computation of the Reduction of Volume of Spills for Methods that Reduce Size and/or Frequency of Spills--

The volume of petroleum spillage that can be prevented (or go undetected) depends upon the capability of reducing both parts of the spill risk, i.e., preventing spills or reducing the size of each spill[a]. As indicated in the previous section, methods that reduce spill size cause the total spill volume to decrease. Also, methods that reduce spill size often affect some reduction in the frequency of spills. However, methods that reduce the frequency of spills also perform a secondary function; they eliminate the spillage volume that would have occurred if the spill had not been prevented. Generally, a spill prevention and control program would be expected to include a combination of methods that result in the reduction of both the frequency and volume of spills.

The following equations can be used to compute the total spillage prevented V_{TP} and spillage undetected V_{TU} for one or more methods that reduce one or both parts of the oil spill risk:

$$V_{SMC} = V_{STC}/F_{STC} \tag{9}$$

$$V_{TRP} = V_{SMC} \times F_{STC} \, (1 - 0.9 \times RRF_{VR} \times RRF_{FR} - 0.1) \tag{10}$$

$$V_{TLP} = V_{SMC} \times F_{STC} \, (1 - 0.1 \times RRF_{VL} \times RRF_{FL} - 0.9) \tag{11}$$

$$V_{TP} = V_{TRP} \times V_{TLP} = V_{SMC} = V_{STC} \, (1 - 0.9 \times RRF_{VR} \times RRF_{FR} - 0.1 \, RRF_{VL} \times RRF_{FL}) \tag{12}$$

$$V_{TU} = V_{STC} - V_{TP} \tag{13}$$

where

V_{SMC} = Mean spill size corrected for line pipe

V_{STC} = Total volume of spills corrected for line pipe

F_{STC} = Total frequency of spills corrected for line pipe

V_{TRP} = Total annual volume of ruptures prevented after installation of leak detection and/or inspection method(s)

---

[a] In the previous approaches for computing the reduction of the frequency and mean volume of spills, methods were assumed to reduce only one part of the risk.

V_{TP} = Total annual volume of spills prevented after installation of leak detection and/or inspection method(s)

V_{TU} = Total annual volume of spills undetected after installation of leak detection and/or inspection method(s).

As an example, a method may have the following risk reduction factors:

$RRF_{VR} = 0.5$

$RRF_{VL} = 1.0$

$RRF_{FR} = 0.5$

$RRF_{FL} = 1.0$.

Assuming V_{SMC} = 1000 barrels/spill and F_{STC} = 100 spills/year, then:

V_{STC} = 1000 barrels/year x 100 spills/year = 100,000 barrels/year

V_{TP} = 1000 barrels/year x 100 spills/year x (1 - 0.9 x 0.5 x 0.5 - 0.1 x 1 x 1) = 100,000 barrels/year (1 - 0.225 - 0.100) = 67,500 barrels/year

V_{TU} = 100,000 barrels/year - 67,500 barrels/year = 32,500 barrels/year.

7.2.2 Estimated Existing and Potential Reduction of Spillage for the Reference Line

Accidental spillage (incidents and volume) from the reference line that can be prevented (or go undetected) is estimated based on information presented in Section 7.2.1. Results for the selected methods are given in Table 72. Estimates are included for leaks and ruptures. In order to provide a general comparison of the capabilities of the selected methods, spillage that can be prevented (or go undetected) is indicated in percentages rather than barrels spilled or number of incidents.

Only a few of the selected methods appear to have the potential of substantially (33 percent or better) decreasing both the incidents and the volume of accidental spillage. These include:

- Visual inspection of the line
    - daily by air or ground patrol
    - daily by ground patrol with hydrocarbon probe or comparable device for indication of the spill
- Passive acoustic array
- Pressure difference
- Survey by inspection pig

TABLE 72. ANALYSIS OF OIL SPILLED FROM THE REFERENCE LINE THAT CAN BE PREVENTED OR GO UNDETECTED

Inspection and/or Leak Detection Methods	Inspection Frequency/ Year	Spillage							
		Prevented						Undetected	
		Spills			Volume			Spills	Volume
		Leaks F_{LP} No.	Ruptures F_{RP} No.	Total F_P No.	Leaks V_{TLP} K bbls	Ruptures V_{TRP} K bbls	Total V_{TP} K bbls	Total F_U No.	Total V_U K bbls
1. Visual line inspection by air or ground patrol (required inspections) for indication of spill	26	0	0	0	0	0	0	290	291
2. Visual line inspection by air or general patrol in excess of required inspection for indications of a spill	a. 26 (Ref)	22	10	32	11	40	57	258	233
	b. 338	71	35	106	23	186	209	184	81
3. Visual inspection by ground patrol with hydrocarbon probe or comparable device for indication of spill (onland lines only	a. 26 (Reg)	39	9	48	9	39	48	242	243
	b. 26	61	19	80	17	78	95	210	196
	c. 338	98	47	145	26	206	232	145	58
4. Hydrocarbon probe-towfish or similar device									
- Underwater lines only	6	6	1	7	2	10	12	22	17
- All lines	6	6	1	7	2	10	12	283	277
5. Pressure deviations									
a. Pump stations (existing method)	continuous	NA	NA	NA	NA	NA	NA	NA	NA
b. Along line	continuous	0	0	0	0	27	27	290	264
6. Flow rate									
a. Deviations	continuous	0	0	0	0	53	53	290	237
b. Comparisons (computerized)	continuous	0	0	0	0	105	105	290	185
7. Volume comparisons (computerized)	continuous	0	0	0	0	183	183	290	107
8. Mathematical modeling (computerized)	continuous	0	0	0	6	235	241	290	50
9. Negative pressure surge (computerized)	continuous	0	0	0	0	80	80	290	211
10. Passive acoustic array (computerized)									
a. Retrofit	a. continuous	46	25	71	6	194	200	219	92
b. New line	b. continuous	82	42	124	14	230	244	166	47
11. External rods with passive acoustic sensors	after indication of spill[a]	0	0	0	3	25	28	290	262
12. Pressure static	after indication of spill[a]	0	0	0	6	52	58	290	233
13. Hydrostatic	a. 1	65	15	80	9	52	61	210	230
	b. 2	69	19	88	17	63	80	202	211
	c. after indication of spill[a]	80	22	102	17	78	95	188	196

(continued)

TABLE 72 (continued)

Inspection and/or Leak Detection Methods	Inspection Frequency/ Year	Spillage							
		Prevented						Undetected	
		Spills			Volume			Spills	Volume
		Leaks F_{LP} No.	Ruptures F_{RP} No.	Total F_P No.	Leaks V_{TLP} K bbls	Ruptures V_{TRP} K bbls	Total V_{TP} K bbls	Total F_U No.	Total V_U K bbls
14. Pressure difference	a. 1	93	20	113	17	73	90	177	201
	b. 2	108	23	131	22	84	106	159	185
	c. 4	148	26	174	26	93	119	116	198
	d. 12	152	29	181	28	105	133	109	186
15. Change or add inhibitors as needed	3[2]	13	3	16	3	12	15	274	276
16. Inspection of sample of line for wall thickness by ultrasonic or comparable technique	1	26	6	32	3	20	23	258	268
17. Survey by inspection pig-magnetic flux type or other comparable device	a. 0.25	87	19	106	12	68	80	184	211
	b. 0.50	100	22	122	13	79	92	168	199
	c. 1	113	24	128	15	90	105	162	186
18. Depth of cover inspection by sonar (sidescan and penetrating) or other comparable device									
- Underwater lines only	4	6	4	10	1	12	13	19	16
- All lines	4	6	4	10	1	12	13	280	278
19. Charting of line pipe									
- Underwater lines only	0.5	2	0	2	0.3	1.4	1.7	27	27.3
- All lines	0.5	2	0	2	0.3	1.4	1.7	288	290
20. Preventive program for outside forces (Reference 12) One-Call System	cont.	59	29	88	10	105	120	202	170
21. Pig line for water removal	3[2]	13	3	16	3	12	15	274	276
22. Oil spill detectors									
- Marine terminal or platform	continuous	0	0	0	1.4	0	1.4	29	27.4
- Total line pipe mileage	continuous	0	0	0	1.4	0	1.4	290	290
23. 10(b) and 13)a)		174	63	237	26	235	261	53	30
24. 17(c) and 20		187	66	253	26	235	261	37	30
25. 3(a), 17(c) and 20		197	69	266	28	250	278	24	13
26. 10(b) and 17(c)		195	63	258	29	250	279	42	12
27. 5(b), 6(a) and 7		0	6	0	0	209	209	290	82
28. 5(a), 6(a), 6(b), 7 and 9		0	0	0	0	248	248	290	43
29. 8 and 17(c)		113	15	128	17	244	261	162	30

Notes:

(1) Estimated annual spillage: Total volume (V_{ST}) = 291,000 barrels; Ruptures(0.9 V_{STC}) = 261,900 barrels; Leaks (0.1 V_{STC}) = 29,100 barrels.
Total spill (F_{ST}) = 290; Ruptures (0.25 F_{ST}) = 73; Leaks (0.75 F_{STC}) = 217.

(2) Frequency of inspection is assumed at three per year.

TYPING GUIDE SHEET

- Preventive program for outside forces
- Depth of cover by sonar or other comparable device[a].

Methods that have the potential of significantly (60 percent or better) decreasing the spill volume include:

- Visual inspection of the line
    - daily by ground patrol with hydrocarbon probe or comparable device
- Volume comparison
- Mathematical modeling
- Passive acoustic array.

Methods that have the potential of substantially (40 percent or better) decreasing the incidents of spills include:

- Visual inspections of the line
    - daily by ground patrol with hydrocarbon probe or comparable device
- Passive acoustic array
- Pressure difference
- Survey by inspection pig-magnetic flux type or other comparable device.

Overall, mathematical modeling and passive acoustic array appear to be the most promising for preventing the greatest volume of spillage; periodic surveys by inspection pigs and the pressure difference method appear to be the most promising for reducing the frequency of spills.

Most methods are highly effective in reducing either the frequency or volume of spills, and in some instances are moderately effective in reducing both parts of the risk. Results indicate that the overall reduction of both the frequency and volume of spills is never better than 50 percent for any method. However, various combinations of as few as two methods result in potential reductions of greater than 80 percent of both the frequency and volume of spills; combinations of three methods or more can result in potential reductions of greater than 90 percent for both the frequency and volume of spills.

7.2.3 Estimated Spillage and Prevention for All U.S. Lines

Total accidental spillage from U.S. lines that can be prevented or go undetected is estimated based on information presented in Section 7.2.1. Results for the selected methods are given in Table 73. Values are provided

---

[a] Underwater lines only.

TABLE 73. ANALYSIS OF OIL SPILLAGE THAT CAN BE PREVENTED OR GO UNDETECTED FOR ALL U.S. LINES

Inspection and/or Leak Detection Methods	Inspections Frequency/ Year	Spillage: Prevented: Spills: Leaks F_{LP} %	Ruptures F_{RP} %	Total F_P %	Prevented: Volume: Leaks V_{TLP} %	Ruptures V_{TRP} %	Total V_{TP} %	Undetected: Spills Total F_U %	Undetected: Volume Total V_U %
1. Visual inspection of line by air or ground patrol (required inspections)	26	0	0	0	0	0	0	100	100
2. Visual inspection of line by air or ground patrol in excess of required inspections	a. 26(ref) b. 338	10 33	14 49	11 37	38 79	18 71	20 72	89 63	80 28
3. Visual inspection of line by ground patrol with hydrocarbon probe or comparable device for indication of spill	a. 26(reg) b. 26 c. 338	18 28 45	12 26 64	17 28 50	31 59 90	15 30 79	16 33 80	83 72 50	84 67 20
4. Hydrocarbon probe-towfish or similar device - Underwater lines only - All lines	6 6	30 3	20 1	24 2.4	69 10	38 4	41 4.1	76 98	59 95
5. Pressure deviations a. Pump stations (existing method) b. Along line	continuous continuous	0 0	0 0	0 0	0 0	0 10	0 9	100 100	100 32
6. Flow rate a. Deviations b. Comparisons (computerized)	continuous continuous	0 0	0 0	0 0	0 0	20 40	18 36	100 100	81 64
7. Volume comparisons (computerized)	continuous	0	0	0	0	70	63	100	37
8. Mathematical modeling (computerized)	continuous	0	0	0	21	90	83	100	17
9. Negative pressure surge (computerized)	continuous	0	0	0	0	30	27	100	73
10. Passive acoustic array (computerized)	a. continuous[3] b. continuous[3]	21 38	34 58	30 43	21 48	74 88	70 84	70 57	30 16
11. External rods with passive acoustic sensors	after indication of spill[4]	0	0	0	10	10	10	100	90
12. Pressure static	after indication of rupture[4]	0	0	6	21	20	20	100	80
13. Hydrostatic	a. 1 b. 2 c. after indication of rupture[4]	30 32 37	20 24 30	28 30 35	31 59 59	20 24 30	21 27 33	72 70 65	79 73 67

(continued)

TABLE 73 (continued)

Inspection and/or Leak Detection Methods	Inspections Frequency/ Year	Spillage							
		Prevented						Undetected	
		Spills			Volume				
		Leaks F_{LP} %	Ruptures F_{RP} %	Total F_P %	Leaks V_{ILP} %	Ruptures V_{THP} %	Total V_{IP} %	Spills Total F_U %	Volume Total V_U %
14. Pressure difference	a. 1	43	28	39	59	28	31	61	69
	b. 2	50	32	45	76	32	36	55	64
	c. 4	68	36	60	90	35	41	40	68
	d. 12	70	40	62	97	40	46	38	64
15. Change or add inhibitors as needed	3[4]	6	4	6	10	5	5	94	95
16. Inspection of sample of line for wall thickness by ultrasonic or comparable technique	1	12	8	11	10	76	8	89	92
17. Survey by inspection pig-magnetic flux type or other comparable device	a. 0.25	40	26	36	40	26	28	64	74
	b. 0.50	46	30	42	46	30	32	58	70
	c. 1	52	34	48	52	34	36	52	64
18. Depth of cover inspection - Underwater	4	28	48	34	34	46	45	66	55
- All lines	4	3	6	3	3	5	4	97	96
19. Charting of line pipe - Underwater	1	9	6	6	10	4.6	5	94	95
- All lines	1	1	1	0	1	1	1	99	99
20. Preventive program for outside forces (Reference 12) One-Call System	cont.	27	40	30	33	40	39	70	61
21. Pig line for water removal	3[4]	6	4	6	10	5	5	94	95
22. Oil spill detectors									
- Marine terminal or platform	continuous	0	0	0	48	0	5	100	94
- Total line pipe mileage	continuous	0	0	0	5	0	0	100	100
23. 10(b) and 13(a)		80	88	82	90	90	90	18	10
24. 17(c) and 20		86	90	87	90	90	90	13	10
25. 3(a), 17(c) and 20		91	95	92	97	95	96	14	4
26. 10(b) and 17(c)		90	86	89	99	95	96	14	4
27. 5(b), 6(a) and 7		0	0	0	0	80	72	100	28
28. 5(a), 6(a), 6(b), 7 and 9		0	0	0	0	95	85	100	15
29. 8 and 17(c)		52	33	44	59	93	90	56	10

Notes:

(1) Annual spillage: Total volume (V_{ST}) = 1.3 barrels; Ruptures (0.90 V_{STC}) = 1.17 barrels; Leaks (0.1 V_{STC}) = 0.13 barrels.
Total spills (F_{ST}) = 1.3×10^{-3}; Ruptures (0.25 F_{ST}) = 0.32×10^{-3}; Leaks (0.75 F_{STC}) = 0.98×10^{-3}.

(2) Retrofit installation.

(3) New line installation.

(4) Frequency of inspection is assumed at three per year.

for both the frequency (number of incidents) and volume (barrels of oil) of spills that can be prevented (or go undetected). Estimates are included for leaks and ruptures.

The relative effectiveness of the methods is, of course, similar to results presented in the previous section for the reference line pipe. Annual inspections of the line can be quite effective. For example, yearly surveys by an inspection pig can potentially prevent 128 spills and eliminate 100,000 barrels spilled. On a comparative basis, this particular inspection potentially could result in reducing the frequency and volume of spills by a factor of at least three times better than cathodic protection systems. Use of more than one method can result in substantial reductions in the reported spill incidents and volume. For example, annual surveys by inspection pigs and implementation of a mathematical modeling system on the lines can potentially result in a reduction of 128 spills and prevention of spillage of 244,000 barrels yearly. The dual prevention capability is particularly desirable for use in older smaller diameter lines where the incidents of spills are high, but spill volume relatively low. In cases of large-diameter lines, where high throughput presents a continuing potential danger of a major spill, methods that are particularly effective in reducing the volume of spills are highly desirable. For example, computerized mathematical modeling or volume comparison methods are expected to reduce the annual spill volume by 240,000 barrels and 185,000 barrels, respectively.

7.3 COST ANALYSIS

Costs of inspections and spillage are extremely important in the development of a practical spill prevention program. All significant costs must be obtained to properly evaluate the cost and cost-effectiveness of the various options (methods and schedules). When a number of options are suitable for spill prevention and control, inspection costs would normally be the most important factor in recommending a particular method. When high spillage costs are expected, such as in high risk areas, additional inspections or methods may be justified. Costs for inspections and leak detection and spillage are discussed in the following subsection.

7.3.1 Inspection and Leak Detection Costs

Significant cost items for implementation of each inspection or leak detection method are included in the estimate of the total inspection cost. Costing includes such items as:

- Equipment
- Installation
- Interest
- Operation
- Maintenance
- Facility downtime

- Training
- Inspection services.

Cost estimates, with a baseline year 1978, were made using data supplied by inspection services, equipment manufacturers, operators, industry surveys, trade journals and from a number of references in this study.

The reference line is assumed for estimating the costs of the various inspection and leak detection methods. The assumptions for the reference line are given in Tables 56 and 74. The reference line is assumed to consist of 300 miles of onland and 30 miles of underwater lines. Costs for the reference line are multiplied by a factor of 676 (mileage of U.S. lines/mileage of reference line) to obtain an estimate for all U.S. petroleum pipelines. Typical costs of equipment and/or inspection services that are assumed for the cost analysis are shown in Table 75.

Costs for methods requiring purchase of equipment and/or permanent or semi-permanent installations were obtained by first estimating the equipment costs. Added to this value was a 25 percent cost for installation. Yearly maintenance and operational costs were assumed to be five percent of the cost of equipment and installation. The equipment was assumed to have a life of ten years with no salvage value. Total annual costs were computed by amortizing the equipment and installation costs over a ten-year period and then adding the maintenance and operational costs.

Estimates of the yearly costs[a] (equipment, installation, maintenance, operation, etc.) of the selected leak detection and inspection methods for the reference line and all U.S. lines are presented in Table 76. These estimates are presented on an annual basis and do not include interest and inflationary costs[b]; this is done to help simplify the comparison of methods that may not require equipment or installation, such as line walking, with those methods that do, such as flow deviation monitoring. It is normally assumed in the costing that implementation of the various methods can be accomplished either by limited interference (retrofitting) or not interference with the line.

---

[a] Costing is developed at a level suitable for evaluation purposes of this study only. Cost estimates are based on an assumed reference line. Detailed costing and optimum accounting for each method is beyond the scope of this study. Costs for a specific line may vary considerably.

[b] Interest and inflationary costs are not needed for the cost analysis. Equipment costs (once purchased) are fixed and thus affected by interest costs and not significantly affected by inflationary costs. Labor, rentals, or inspection services are affected by inflationary costs but not significantly affected by interest costs.

TABLE 74. ASSUMPTIONS FOR REFERENCE LINE

Mileage:	Onland - total 300 miles - crude gathering lines - crude trunklines - product trunklines
	Underwater - total 30 miles - crude gathering lines 20 miles - crude trunklines 10 miles - product trunklines
Pump Station:	Number - 6 Spacing - 50 miles
Inlet and Outlet Meter:	Number - 3 Spacing - 100 miles
Corrosion Monitor:	Number - 30 Spacing - 10 miles
Marine Terminal:	1

EPA Form 2280-4 (4-80)
TYPING GUIDE SHEET

TABLE 75. EQUIPMENT AND INSPECTION SERVICE COSTS FOR SELECTED LEAK DETECTION AND INSPECTION METHODS

Item No.	Equipment or Inspection Service	Estimated Cost
1	Air patrol line pipe inspection service	$0.50 / mile
2	Ground patrol	$4.00 / mile
3	Hydrocarbon probe or equivalent	$2,000 / meter
4	Ground patrol with hydrocarbon probe or other comparable device	$250 / day
5	Hydrocarbon probe (towfish type) or other comparable device	
	- lease or rent system	$250 / day
	- operator	$200 / day
6	Oil spill detector system	$7,000 / unit
7	Line pressure meter	$2,000 / meter
8	Telemetry for remote monitoring	$3,000 / unit
9	Telephone lines for remote monitoring	$5,000 / station
10	Leak detection display, control and alarms for pressure monitoring and/or flow monitoring	$3,000 / pump station
11	Flow meter system	$15,000 / pump station
12	Correction equipment for flow transients	$10,000 / pump station
13	Inlet and outlet meters modified for leak detection	$5,000 / meter
14	Leak detection display, control and alarms - flow rate comparison	$5,000 / pump station
	- master control room	$10,000 / line
15	Central minicomputer	$100,000 / line
16	Real-time pipeline model software	$50,000 / line
17	Negative pressure surge monitor	$5,000 / unit
18	Acoustic detector (portable)	$500 / detector
19	Acoustic analyzer and display	$3,000 / unit
20	Acoustic detector and signal conditioning (permanently installed)	$200 / unit
21	Acoustic transmission/receiver cabling - on land	$2,500 / mile
	- underwater	$10,000 / mile
22	Acoustic master unit	$10,000 / station
23	Acoustic central minicomputer	$100,000 / line
24	Remotely controlled block valves with pressure difference transducers (includes valve, transducers, power, telemetry units, connectors to telephone lines)	$20,000 / valve
25	Laboratory equipment for analysis of fluid in line	$2,000 / unit
26	Survey inspection pig-magnetic flux type or equivalent -by inspection service	$500 / mile
27	Depth of cover inspection of underwater lines by inspection service	$300 / mile
28	Sonar system (sidescan and penetrating) towfish type or other comparable device	
	- lease or rental of equipment	$500 / day
	- operator	$200 / day
29	Charting of underwater lines by inspection service	$300 / mile

TABLE 76. COST OF INSPECTION AND LEAK DETECTION METHODS

Inspection and/or Leak Detection Methods	INSPECTIONS	ANNUAL COSTS		
		Reference Line		All U.S. Lines
	Frequency/ Year	Per[(1)] Mile $	Total $ K	Total $ Million
1. Visual line inspection by air or ground patrol (Required inspections for indication of spill)	26	14	4.8	3
2. Visual line inspection by air or general patrol in excess of re-quited inspection for indications of a spill	a. 26 (Ref.)	14	4.8	3
	b. 338	187	62	42
3. Visual inspection by ground patrol with hydrocarbon probe or comparable device for indication of spill (onland lines only)	a. 26 (Reg.)	110	33	22
	b. 26	220	66	44
	c. 338	1,420	429	286
4. Hydrocarbon probe-towfish or similar device -Underwater lines only	6	1,200	36	24
5. Pressure deviations				
a. Pump stations (existing method)	continuous	NA (3)	NA(3)	NA(3)
b. Along line	continuous	85	28	19
6. Flow rate				
a. Deviations	continuous	68	23	15
b. Comparisons (computerized)	continuous	185	61	41
7. Volume comparisons (computerized)	continuous	185	61	41
8. Mathematical modeling (computerized)	continuous	212	70	47
9. Negative pressure surge (computerized)	continuous	159	52	35
10. Passive acoustic array (computerized)				
a. Retrofit	continuous	210	70	46
b. New line	continuous	954	315	210
11. External rods with passive acoustic sensors	after indication of spill(2)	59	18	12
12. Pressure static	after indication of spill(2)	9	3	2
13. Hydrostatic	a. 1	36	12	8
	b. 2	72	24	16
	c. after indication of spill(2)	36	12	8

(continued)

EPA Form 2350-4 (4-60)
TYPING GUIDE SHEET

TABLE 76 (continued)

Inspection and/or Leak Detection Methods	INSPECTIONS Frequency/ Year	ANNUAL COSTS Reference Line Per(1) Mile $	Reference Line Total $ K	All U.S. Lines Total $ Million
14. Pressure difference	a. 1	290	96	64
	b. 2	327	108	72
	c. 4	400	132	88
	d. 12	690	228	152
15. Change or add inhibitors as needed	3(2)	4	1.2	0.8
16. Inspection of sample of line for wall thickness by ultrasonic or comparable technique.	1	87	26	18
17. Survey by inspection pig-magnetic flux type or other comparable device	a. 0.25	125	42	28
	b. 0.50	250	83	56
	c. 1	500	165	111
18. Depth of cover inspection by sonar (sidescan and penetrating) or other comparable device -Underwater lines only	4	1,200	36	24
19. Charting of line pipe -Underwater lines only	0.5	150	4.5	3
20. Preventive program for outside forces (Reference 12) One-Call System	Cont.	45	15	10
21. Pig line for water removal (low elevation only)	3(2)	15	5	3
22. Oil spill detectors -Marine terminal or platform -Total line pipe mileage	 continuous continuous	 16 16	 5.2 5.2	 3.5 3.5
23. 10 (b) and 13 (a)		1,000	327	218
24. 17 (a) and 20				
25. 3 (a), 17 (c) and 20				
26. 10 (b) and 17 (c)		1,080	357	238
27. 5 (b), 6 (a), 7		303	100	67
28. 5 (a), 6 (a), 6 (b), 7 and 9		454	150	100
29. 8 and 17 (c)		712	235	156

NOTE: (1) Cost per mile for single inspection can be computed by dividing the cost by number of inspections/year

(2) Frequency of inspection is assumed at three per year

(3) NA - Not applicable since method is commonly used

TYPING GUIDE SHEET

Typical construction costs per mile for offshore pipeline are shown in Table 77 for various diameters. This information is useful in comparing the cost of the pipeline and the cost of spill prevention.

Pertinent items assumed for the selected methods are provided in the subsections that follow.

7.3.1.1 Cost of Selected Visual and Visual-Aided Line Inspections--

Visual inspections of the line pipe are normally carried out in the U.S. by air patrol inspection services. Cost estimates are based on inspections by air patrol services with some adjustments for the limited use of ground patrol by the pipeline company personnel. Air patrol inspections services[a] are estimated at 50 cents per mile for each inspection. Ground patrol inspections are estimated at four dollars per mile. Inspections carried out every two weeks are estimated to cost approximately 3.2 million dollars each year for all U.S. lines.

Ground patrol inspections with a hydrocarbon probe or other comparable devices are estimated at 4.2 dollars per mile for each inspection. Inspections carried out every two weeks are estimated to cost approximately 22 million dollars each year for all onland U.S. lines.

Inspections of underwater lines using a hydrocarbon towfish or other comparable devices are expected to cost approximately 200 dollars per mile for each inspection. These inspections are normally performed by inspection services that provide both the equipment and the operator. A boar (with a winch) and support crew are also required. Inspections carried out every two months are estimated to cost approximately 36,000 dollars for the reference line and 24 million dollars each year for all underwater U.S. lines.

7.3.1.2 Cost of Selected Method for Oil Spill Detectors on or Near the Water--

The method employing oil spill detectors at marine terminals and offshore platforms would typically require about four detectors at each location. Annual costs are estimated at 5,200 dollars for the reference line and 3.5 million dollars for all U.S. lines.

---

[a] Cost of electronic monitoring by air patrol of the corrosion monitors installed on the line, typically spaced at 5 to 15 miles, are not included. However, this service is estimated at 50 cents per mile assuming bi-weekly inspections. Typically, the monthly charge for each monitor is about ten dollars.

TABLE 77. OFFSHORE PIPELINE CONSTRUCTION COSTS[a]

Diameter (inch)	Cost Installation $K/mile	 Yearly[b] $K/mile
6	250	5.0
8	262	5.24
10	278	5.56
12	300	6.0
14	325	6.5
16	350	7.0
18	385	7.7
20	420	8.4
22	465	9.3
24	510	10.2
26	576	11.5
28	642	12.8
30	720	14.4
32	810	16.2
36	1,010	20.2
40	1,290	25.8
42	1,440	28.8
44	1,660	33.2
48	2,210	44.2

[a] Source: CEQ 1974, Inflated 31 percent (Ocean Industry pipeline inflation factor) to convert 1972 dollars to 1975 dollars.

[b] Assumes 50-year life with no salvage value.

TYPING GUIDE SHEET

7.3.1.3 Cost of Selected Methods for Continuous Monitoring of Internal Fluid Variations During Transfer--

The method employing continuous monitoring of pressure deviations along the line is assumed to include the existing pressure monitoring systems at each pump station and new installations at two locations (approximately 16 miles apart) between each pump station. Twelve of these stations would typically be installed on the reference line. Other equipment includes telemetry and telephone lines at remote monitoring stations and leak detection displays, controls and alarms at each pump station. Annual costs are estimated at 28,000 dollars for the reference line and 19 million dollars for all U.S. lines.

The computerized flow rate comparison method requires the installation of flow meters at each pump station and modification (for leak detection) of inlet and outlet meters typically at three locations. Other equipment includes electronics that connect flow meter to telephone lines, leak detection monitoring units with control and alarms and correction equipment for flow transients at each pump station, and a central minicomputer at the main control room. Annual costs are estimated at 61,000 dollars for the reference line and 41 million dollars for all U.S. lines.

Costs for implementing the computerized volume comparison method are about the same as for the flow comparison method. Similar equipment is required.

The mathematical modeling method requires equipment similar to the volume comparison method. However, some additional equipment is required for implementing the real-time pipeline model. Typically, the equipment is implemented in the central computer as a software implemented system. Annual costs are estimated at 70,000 dollars for the reference line and 47 million dollars for all U.S. lines.

Implementation of the negative pressure surge method primarily requires installation of pressure surge monitoring stations at the pump stations and at various locations, typically at two stations approximately 16 miles apart, between each pump station. A total of 18 stations typically would be required. Other equipment includes telemetry and telephone lines for remote monitoring and a central minicomputer at the central control room. Annual costs are estimated at 50,500 dollars for the reference line or 35 million dollars for all U.S. lines.

7.3.1.4 Cost of Selected Methods for Detection and Location of Spills on or at a Short Distance from the Line Pipe--

The major installation required for the method employing external rods with passive acoustic sensor are the metal rods permanently attached (by brazing) to the lines. The rods are typically spaced approximately one-quarter mile apart. Portable acoustic sensors with associated analyzing equipment normally would be stored at each pump station. Annual costs are estimated at 17,600 dollars for the reference line and 12 million dollars for all U.S. lines. This estimate does not include installation on underwater lines.

Two cost values are provided for the passive acoustic array inspection. One cost is based on a typical system for retrofit installations. The second cost is based on a typical system for new lines. A system retrofitted to the line is expected to be capable primarily of preventing damage by outside forces and detecting ruptures, while a system for a new line is expected to be capable of preventing most failures and detecting most leaks. Costs for this latter system are expected to be too high for most existing lines because of the large number of sensors and associated equipment and the high expense to uncover the line for equipment installation. However, this system should be considered for short sections of lines in high risk areas, i.e., underwater.

For retrofitting on existing lines, the passive acoustic array method is expected to require installation of acoustic transducers at the pump station and at various locations, typically at four stations (approximately ten miles apart), between each pump station. Other equipment includes signal conditioning, signal processing, and telemetry and telephone lines for remote monitoring. Annual costs are estimated at 69,600 dollars or 46 million dollars for all U.S. lines.

For installation on new lines, acoustic sensors with signal conditioning and signal processing equipment are expected to be installed at approximately five locations each mile. Typically, a multiconductor cable running the length of the line would provide both power and transmission of the signal from each acoustic sensor. (Numerous other means, such as telemetry data link, might also be used for transmission of the acoustic signal from line pipe to the control room.) Master units supply the power, signal processing and control. These units would be located at each pump station and at two locations between each pump station. Annual costs for a new line are estimated at 315,000 dollars or 210 million dollars for all U.S. lines.

7.3.1.5 Cost of Selected Methods for Periodic Pressure Tests--

Pressure static tests are expected to be of low cost. For a typical test, the line would be held at normal line pressure for a short time interval (less than one hour). Normally long sections of the line would be tested separately and a few hours would be required for a complete test. It is assumed that mainline valves would require manual closure. Yearly costs[a], assuming tests are carried out three times, are expected to be about 3,000 dollars for the reference line and 2 million dollars for all U.S. lines.

Hydrostatic tests are based on test section spacings of about 16 miles and hold times of about 24 hours. Annual inspections are estimated to cost[a] approximately 12,000 dollars for the reference line and 8 million dollars for all U.S. lines. Hydrostatic tests carried out only after an indication of a leak are expected to be about the same cost. For this latter test scheme, only a limited number of line sections would be tested. Inspections are expected to be carried out about three times a year.

---

[a] Line downtime and leak location costs are not included in the estimate for this inspection.

7.3.1.6 Costs of Selected Corrosion Inspection Methods--

Inspections for internal pipeline corrosion through laboratory analysis of fluid transported could be carried out by either operating company personnel or outside inspection services. Equipment for analysis of the fluid can be either purchased or leased. Costs are based on the assumptions that the inspection is done by an outside service three times a year. Annual costs are estimated at 1200 dollars for the reference line and 800,000 dollars for all U.S. lines.

7.3.1.7 Costs of Selected Standard Non-Destructive Testing Methods--

Inspections of sample sections of the line for wall thickness changes by ultrasonic or comparable techniques are assumed to be carried out by an inspection service. The cost estimate is based on inspection of small areas of the line pipe at a spacing of approximately two miles. Annual costs are estimated at 26,000 dollars for the reference line and 17.6 million dollars for all U.S. lines.

7.3.1.8 Cost for Selected Inspection Pigs--

Inspection of the line using inspection pigs (magnetic flux type or other comparable devices) are normally carried out by inspection services. Costs are estimated at 500 dollars per mile per inspection. Annual costs are estimated at 165,000 dollars for the reference line and 111 million dollars for all U.S. lines.

7.3.1.9 Cost of Selected Methods for Line Pipe Charting and Depth of Cover--

Inspections of the depth of cover of underwater lines using a sonar (sidescan and penetrating) towfish or other comparable device would typically be carried out by inspection services that provide equipment and an equipment operator. A boat (with winch) and a support crew are also required. These inspections are expected to cost approximately 300 dollars per mile for each inspection. Inspections carried out every three months are estimated to cost 36,000 dollars for the reference line and 24 million dollars each year for all underwater lines in the U.S.

Charting the location of underwater lines is normally carried out by inspection services. A diver, support crew and a boat are the major cost items. Inspection costs are estimated at 300 dollars per mile. Annual costs are estimated at 4,500 dollars for the reference line and 3 million dollars for all underwater lines in the U.S.

---

[a] Underwater lines are not included in this cost estimate.

EPA Form 2350-4 (4-80)
(PREVIOUSLY CIN. EPA FORM 287)
TYPING GUIDE SHEET

7.3.2 Spillage Costs

Spillage costs in the study are separated into the following three major categories:

- Petroleum spilled from line pipe
- Spill cleanup (function of the location and means of spill cleanup)
- External damage (function of the severity or risks external to the line).

Separation into these three cost categories is particularly advantageous for both the cost-effectiveness analysis carried out in Section 7.4 and the selection of methods for lines located in high risk areas. Spillage cost for each category will be discussed in the subsections that follow.

7.3.2.1 Petroleum Spilled--

The cost (value) of petroleum spilled from line pipe is difficult to estimate because of the wide range of petroleum prices that exist for crude (imported, new production wells, old production wells, etc.) and product (various types). To avoid this problem, the costs of petroleum spilled are evaluated based on the quantity (in barrels) rather than the actual cost (dollars). Conversion from barrels lost to dollar values can be made directly for any specific line or nationwide based on average petroleum costs.

7.3.2.2 Spill Cleanup--Cost Factor (Function of the Location and Means of Spill Cleanup)--

Spillage costs for spill cleanup vary widely. However, these costs generally depend on the location and means of cleanup of the spill. For example, a spill located in a remote area at large distances from roads would be very costly to clean up using typical oil recovery methods, but the cost of burning the lost oil would be much lower. In this study, standard oil recovery methods will be assumed.

Values for the cost factors SCF_{SC} that account for the location and means of spill cleanup are provided in Table 78. These factors are qualitative estimates based upon information obtained from companies carrying out spill cleanup, from a typical operating company and information available in the literature. It should be noted that these cost factors can vary widely depending upon company practices or local regulations for a particular line. For example, if spilled petroleum were burned onland costs of cleanup would be minimal.

7.3.2.3 External Damage--Cost Factor (Function of Severity or Risks External to the Line)--

Spillage costs for damage external to the line from a spill also vary widely. However, these costs generally depend upon the risks that exist external to the line.

BEGIN FIRST LINE OF TEXT HERE
CENTER OF PAGE
TOP OF IMAGE AREA
DROPPED HEAD: BEGIN SECTIONS HERE
BEGIN LAST LINE OF TEXT
BOTTOM OF IMAGE AREA OUTSIDE DIMENSION FOR TABLES AND ILLUSTRATIONS
3/8"
PAGE NUMBER
EPA Form 2350-4 (4-80)
(PREVIOUSLY CIN. EPA FORM 387)
TYPING GUIDE SHEET

TABLE 78. SPILL CLEANUP COST FACTORS AS A FUNCTION OF THE LOCATION OF SPILL

Location	Cost Factors SCF_{SC}
Onland	
Easy access	1
Moderate access	2
Difficult access	5
Underwater	
Confined area	50
Offshore	100

EPA Form 2350-4 (4-60)
TYPING GUIDE SHEET

Values for the cost factor SCF_{ED} that account for severity of the spill or risks external to the line can be obtained from Table 58. This cost factor is assumed to be identical to the overall risk correction factor CF_{ED} presented in Section 7.3.3.4.

7.4 COST-EFFECTIVENESS ANALYSIS

An analysis of the cost-effectiveness of the selected inspection and leak detection methods for various inspection schedules is carried out in this section. The analysis accounts for both effectiveness (the capability of methods to reduce the incidents and volume of spillage) and the costs (inspection methods and spillage). The cost-effectiveness of the various options is the most important consideration in the development of a practical spill prevention and control program for line pipe. The need for evaluation based on cost-effectiveness arises because of the variety and number of options at various costs that are available for reducing the risks of oil escaping from the line.

A general measure of cost-effectiveness CE_{GM} based on the ratio of the reduction of barrels of oil spilled to the inspection costs is presented in Section 7.4.1. This measure applies to most lines. Values are computed for the selected methods and results discussed.

A second or specialized measure of cost-effectiveness CE_{SM} is presented in Section 7.4.2. It accounts for spillage from lines located in areas where the potential exists for high spillage cleanup costs and/or high spill risks external to the line. This measure should be used for individual lines where special spill prevention and control may be needed because of the potential of serious and/or costly spillage.

7.4.1 General Measure of Cost-Effectiveness

The general measure of cost-effectiveness CE_{GM} accounts for the volume or incidents of spillage (barrels) and inspection costs. It is defined as:

For Volume Spilled

$$GE_{GM} = \frac{\text{spillage (barrels of oil prevented)}}{\text{inspection costs}}$$

or

For Incidents

$$CE_{GM} = \frac{\text{spillage (number of incidents prevented)}}{\text{inspection costs}} .$$

Values for the selected methods are given in Table 79.

Two main reasons for using the general measure of cost-effectiveness are:

TABLE 79. COST-EFFECTIVENESS ANALYSIS FOR ALL U.S. LINES

Inspection and/or Leak Detection Methods	INSPECTIONS	ANNUAL COSTS	SPILLAGE PREVENTED		COST EFFECTIVENESS	
	Frequency/ Year	U.S. Lines Total $ Million	Incidents Reduced No.	Volume Saved K bbls	Incidents Reduced / cost No./$ K	Volume Saved / cost bbls/$ K
1. Visual line inspection by air or ground patrol (Required inspections for indication of spill)	26	3	0	0	NA	NA
2. Visual line inspection by air or general patrol in excess of requited inspection for indications of a spill	a. 26 (Ref.)	3	32	57	10.7	19
	b. 338	42	106	209	2.5	5.0
3. Visual inspection by ground patrol with hydrocarbon probe or comparable device for indication of spill (onland lines only)	a. 26 (Reg.)	22	48	48	2.2	2.2
	b. 26	44	80	95	1.8	2.2
	c. 338	286	145	232	0.5	0.8
4. Hydrocarbon probe-towfish or similar device						
-Underwater lines only	6	24	7	12	0.3	0.5
-All lines	6	24	7	12	0.3	0.5
5. Pressure deviations						
a. Pump stations (existing method)	continuous	NA(1)	NA(1)	NA(1)	NA(1)	NA(1)
b. Along line	continuous	19	0	27	0	1.4
6. Flow rate						
a. Deviations	continuous	15	0	53	0	3.5
b. Comparisons (computerized)	continuous	41	0	105	0	2.6
7. Volume comparisons (computerized)	continuous	41	0	183	0	4.5
8. Mathematical modeling (computerized)	continuous	47	0	241	0	5.1
9. Negative pressure surge (computerized)	continuous	35	0	80	0	2.3
10. Passive acoustic array (computerized)						
a. Retrofit	continuous	46	71	200	1.5	4.3
b. New line	continuous	210	124	244	0.6	1.2
11. External rods with passive acoustic sensors	after indication of spill(2)	12	0	24	0	2.0
12. Pressure static	after indication of spill(2)	2	0	58	0	29
13. Hydrostatic	a. 1	8	80	61	10.0	7.6
	b. 2	16	88	80	5.5	5.0
	c. after indication of spill(2)	8	102	95	12.8	11.9

(continued)

TABLE 79 (continued)

Inspection and/or Leak Detection Methods	INSPECTIONS	ANNUAL COSTS	SPILLAGE PREVENTED		COST EFFECTIVENESS	
	Frequency/ Year	U.S. Lines Total $ Million	Incidents Reduced No.	Volume Saved K bbls	Incidents Reduced / cost No. / $ K	Volume Saved / cost bbls / $ K
14. Pressure difference	a. 1 b. 2 c. 4 d. 12	64 72 88 152	113 131 174 181	90 106 119 133	1.8 1.8 2.0 1.2	1.4 1.5 1.3 0.9
15. Change or add inhibitors as needed	3(3)	0.8	16	15	20	19.8
16. Inspection of sample of line for wall thickness by ultrasonic or comparable technique.	1	18	32	23	1.8	12.8
17. Survey by inspection pig-magnetic flux type or other comparable device	a. 0.25 b. 0.50 c. 1	28 56 111	106 122 128	80 92 105	3.8 2.2 1.15	2.9 1.6 0.9
18. Depth of cover inspection by sonar (sidescan and penetrating) or other comparable device -Underwater lines only -All lines	 4 4	 24 24	 10 10	 13 13	 4.2 4.2	 0.5 0.5
19. Charting of line pipe -Underwater lines only -All lines	 0.5 0.5	 3 3	 2 2	 1.7 1.7	 0.7 0.7	 0.7 0.7
20. Preventive program for outside forces (Reference 12) One-Call System	cont.	10	88	120	8.8	12
21. Pig line for water removal	3(3)	3	16	15	5.3	3
22. Oil spill detectors -Marine terminal or platform -Total line pipe mileage	 continuous continuous	 3.5 3.5	 0 0	 1.4 1.4	 0 0	 0.4 0.4
23. 10 (b) and 13 (a)		218	237	261	1.1	1.2
24. 17 (a) and 20			253	261		
25. 3 (a), 17 (c) and 20			266	278		
26. 10 (b) and 17 (c)		238	258	279	1.1	1.2
27. 5 (b), 6 (a), 7		67	0	209	0	3.1
28. 5 (a), 6 (a), 6 (b), 7 and 9		100	0	248	0	2.4
29. 8 and 17 (c)		156	128	261	0.8	1.7

NOTE:

(1) NA - Not applicable since method is commonly used.

(2) Cost per mile for single inspection can be computed by dividing the cost by number of inspections/year.

(3) Frequency of inspection is assumed at three per year.

- Can be applied to most lines
- Independent of line location, i.e., depends only upon the volume of petroleum escaping from the line.

This measure is particularly useful in the consideration of guidelines or recommendations for a general spill prevention and control program that might be developed for a typical line by the operating company or for most U.S. lines by a nationwide program.

7.4.2 Special Measure of Cost-Effectiveness

High spillage costs are possible in certain locations where high spill cleanup costs are expected or in areas where high oil spill risks to the environment exist external to the lines. These two sources of spillage costs[a] are not directly accounted for in the general measure of cost-effectiveness. In order to account for both of these spillage costs, a second or special measure of cost-effectiveness CF_{SM} is provided. It is defined as:

$$CE_{SM} = CE_{GM} \times SCF$$

and

$$SCF = SCF_{SC} \times SCF_{ED}$$

where

CE_{SM} = special measure of cost-effectiveness

CE_{GM} = general measure of cost-effectiveness

SCF = spillage cost factor

SCF_{SC} = spillage cost factor for spill cleanup as function of the location of spill (see Section 7.3.2)

SCF_{ED}[b] = CF_{ED} = spillage cost factor for risks external to the line (see Section 7.3.3).

---

[a] Spillage costs due to risks of the external environment are accounted for when the risk correction factor CF_{ED} for risks external to the line is used in estimating the oil spill risk of a particular line or group of lines.

[b] If the risk correction factor CF_{ED} was used in estimating the oil spill risk the spillage cost factor SCF_{ED} for risks external to the line is given a value of 1.

The special measure of cost-effectiveness requires only the inclusion of the spillage cost factor. Thus, the relative cost-effectiveness of the available options (see Section 7.3.1), based on the general measure of cost-effectiveness, does not change.

As the costs of spillage increases, the cost-effectiveness[a] of the various options becomes greater. For example, if a line were located offshore the cost-effectiveness of each method would be substantially greater than for a typical onland line. This obvious improvement in the cost-effectiveness is indicated in the special measure of cost-effectiveness. Improvement in cost-effectiveness often allows the user greater range of selection, from a cost basis, of the various available options.

The special measure of cost-effectiveness should be considered in the development of spill prevention and control programs for lines located in areas where the following spillage problems exist:

- Potential of serious spill problems or high risks external to the line pipe exists, i.e., the risk correction factor CF_{ED} is greater than 3.
- Spill cleanup costs are expected to be high, i.e., the cost correction factor is greater than 3.

When the potential of these spillage problems exists, a more effective spill prevention and control program is often needed. This might require more effective methods (greater spill reduction capability) and/or more frequent inspections.

---

[a] For many lines, the additional costs of spillage may be so high that an adequate spill prevention program may, in fact, result over the long-term in substantial cost savings and other benefits.

EPA Form 2300-4 (4-80)
TYPING GUIDE SHEET

SECTION 8

RECOMMENDATIONS

8.1 DISCUSSION

Results of this study show that the potential exists for serious spills from the line pipe of petroleum pipeline systems and that various options, inspection and leak detection methods and schedules, are available to significantly reduce the oil spill risk. Based on the results of this investigation, preventive maintenance programs for line pipe are recommended. These recommendations are based primarily on qualitative[a] estimates of the oil spill risks that exist and the capabilities of various methods to reduce the risks. However, recommendations are also based on practical considerations such as costs of inspections and spillage.

Recommendations are primarily intended to aid the user both in evaluating the need for, and actually developing, a spill prevention and control program for his own line pipe. The recommended programs are expected to significantly improve the prevention and control of accidental spills of petroleum from operational lines. The programs include scheduled inspections and/or in situ leak detection (some functioning continuously) that could be effectively developed and implemented. Overall, the programs provide means of estimating the risks of spills from line pipe and the potential for preventive maintenance.

It should be noted that the statutory requirements and voluntary preventive maintenance programs by operating companies have already resulted in a good safety record for line pipe. In many cases, voluntary individual programs, such as implemented on many large-diameter lines or underwater lines, exceed statutory requirements. Voluntary programs have helped to significantly reduce the spill risk of these individual lines and also have contributed to the good safety record nationwide. Despite these efforts, spills that are costly, hazardous, or could result in a major pollution

---

[a] The intent in this study is to provide the necessary background information and approach so that recommendations are developed from a purely qualitative basis. This is in contrast to most spill prevention plans that are developed based on educated guesses using inadequate and possibly incorrect information derived partly from the literature, manufacturers, experience, hearsay, and quantitative estimates.

EPA Form 2350-4 (4-80)
TYPING GUIDE SHEET

incident can and do occur. The risk of such serious spills is particularly high for certain lines or lines in certain areas. Results of this study indicate that means are available to reduce the possibility of these serious accidental spills and improve the safety record nationwide.

Since there are many variations between lines and wide ranges in the oil spill risk, it is beyond the scope of this study to recommend programs for particular lines. Hence, recommendations are generalized and do not include specific details for implementing methods for particular lines. However, recommended programs are developed that apply to typical lines. Also, sufficient information is provided (see Sections 6 and 7) so that a user may develop a program for his own line.

In order to evaluate the potential of spill prevention programs for pipelines, spill records, the oil spill risks from petroleum pipeline system preventive maintenance programs (statutory, required, voluntary), and the risk reduction capabilities of the various available options (inspection and leak detection methods) were investigated. Costs of inspections and spillage were also studied. Since inadequate quantitative information of the development of spill prevention programs was available for many of the areas investigated, qualitative estimates[a] were made to account for these deficiencies. Then measures were developed for evaluating line pipe oil spill risk (frequency and volume of spills), capabilities of methods to reduce the frequency and volume of spills (effectiveness), costs of inspections and spillage, and cost-effectiveness. Values for these measures were estimated. Finally, the recommended maintenance programs (Section 8.2) were developed based primarily on analysis of the results of these measures. The cost-effectiveness of the various available options (inspections and leak detection methods and schedules), however, was the most important consideration in the recommendations.

Benefits of a preventive maintenance program are discussed in Section 8.2. Although no inspection or leak detection method can be justified purely on the cost savings resulting from the value of oil that would be saved, other factors that might justify preventive maintenance are presented.

A recommended preventive maintenance program for the line pipe of operational line is presented in Section 8.3. Implementation of such a program is expected to decrease substantially the total quantity of petroleum lost, the number of spill incidents and the number of major spill incidents. A recommended approach for the development of a spill prevention program for individual lines is presented in Section 8.3.1. A general spill prevention program is presented in Section 8.3.2 that produces the confidence that lines will have no more than (X) barrels spilled and (X) number of incidents per year. The program consists of a series of recommendations of scheduled inspections and/or in situ leak detection. Finally, recommendations of a specific scheduled preventive maintenance program for all U.S. lines and for special lines (lines with a serious potential that petroleum will escape or those located in high risk areas) are presented in Section 8.3.3. Recommended developmental inspection and lead detection methods are discussed in Section 8.4.

---

[a] An in-depth analysis of these areas for the purpose of obtaining highly accurate estimates is beyond the scope of this study.

8.2 BENEFITS

No inspection or leak detection methods can be justified purely on the cost savings resulting from the value (dollars) of the petroleum saved. However, when other benefits are considered, preventive maintenance is often justified. Overall, damage from spills is becoming more costly and the benefits of spill prevention are evident.

Reduction of spillage costs (i.e., spill cleanup and external damage (see Section 7.3)) is a major consideration in justification of preventive maintenance. This is particularly true of lines located in high risk areas (see Section 7.4) or lines that have a high risk that petroleum will escape (i.e., large diameter lines, old lines, etc.). For many of these lines, the additional costs of spillage may be so high that effective preventive maintenance programs may, in fact, result in substantial cost savings over the long-term.

Benefits such as reduction of risks to personnel or others, reduction of line shutdown, improved public relations, and the saving of the important and valuable petroleum resources, further justify preventive maintenance. Additionally, another important benefit is the reduction of the various socio-economic-legal aspects of spills. For example, in evaluating real or personal property of damage from a spill[83], items such as diminished value, temporary non-use, profit and loss, loss of taxes, penalties, etc., are considered.

8.3 RECOMMENDED PREVENTIVE MAINTENANCE PROGRAM

8.3.1 Individual Lines

The recommended approach for developing a spill prevention program for an individual or group of lines is based on the following steps:

- Estimate the risk that oil will escape from a line (see Section 6.3.4.1)
- Identify locations of a line where a spill may create special serious problems (see Sections 6.3.3.4 and 6.7.2) such as the possible damage to the external environment or the cost of spill cleanup.
- Estimate the level of corrective action to reduce the spill risk to an acceptable level.

EPA Form 2350-4 (4-80)
TYPING GUIDE SHEET

- Identify the various options of a spill prevention program that are available to achieve the necessary reductions in the spill risk (see Sections 8.3.2.2 and 7.1.2).
- Select the optimum methods based on the cost-effectiveness and other considerations of the various suitable options.

8.3.2 General Schedule

The general schedule produces confidence that an individual line or group of lines will have no more than (X) barrels spilled and (X) number of incidents per year. The recommended approach is to first estimate the risk that oil will escape from the line (see Section 6.3.1.1). Then select one of the specific preventive maintenance schedules:

- Reduction of frequency of spills - Table 80
- Reduction of volume of spills - Table 81
- Reduction of frequency and volume of spills - Table 82.

Using the indicated approach and schedules, selectable spilling reductions of greater than 25 percent, 50 percent and 75 percent may be achieved.

8.3.3 Specific Schedule

8.3.3.1 Most U.S. Lines--

Recommendations for typical U.S. lines include:

- Visual inspections of the line by air or ground patrol - weekly
- One-Call System (Reference 12)
- Survey by inspection pig (magnetic flux type or other comparable device - every four years

or

- Hydrostatic tests
  - yearly, or
  - after indication of spill.

Increasing the frequency of visual inspections of the line by air or ground patrol from bi-weekly to weekly is expected to result in annual savings of approximately 57,000 barrels of petroleum (20 percent of total) and decrease in number of incidents by 32 (11 percent of total). These reductions are expected to be achieved at a nominal cost of about 3 million dollars. These inspections are the most cost-effective (19 bbls/$K) of any of the selected methods. Assuming the average cost of petroleum (crudes and products) at 25 dollars per barrel, cost savings of the value of petroleum alone almost justifies these recommended inspections.

EPA Form 2350-4 (4-80)
(PREVIOUSLY CIN. EPA FORM 261)
TYPING GUIDE SHEET

TABLE 80. PREVENTIVE MAINTENANCE SCHEDULES FOR THE REDUCTION OF THE FREQUENCY OF ACCIDENTAL SPILLS FROM LINE PIPE

Inspection and/or Leak Detection Methods	Inspection Frequency/ Year	Percent Reduction of Frequency of Spills																		
		>25% Schedule^{1}								>50% Schedule^{1}					>75% Schedule^{1}					
		A	B	C	D	E	F	G^{3}	H^{3}	A	B	C	D	E^{3}	A	B	C	D^{3}	E^{3}	F^{3}
Visual line inspection by air or ground patrol in excess of required inspections	a. 26								X	X	X			X	X	X		X	X	
	b. 338				X															
Visual inspection by ground patrol with hydrocarbon probe or comparable device for indication of spill (onland lines only)	a. 26																			
	b. 52					X						X								
	c. 338																			
Hydrocarbon probe-towfish or similar device-Underwater lines only	6								X					X				X	X	X
Passive acoustic array (computerized) a. Retrofit	a. continuous						X						X				X			
b. New line	b. continuous																		X	X
Hydrostatic	a. 1																			
	b. 2																			
	c. after indication of spill^{2}	X								X							X			
Pressure difference	a. 1																			
	b. 2																			
	c. 4																			
	d. 12																			
Change or add inhibitors as needed	3^{2}																			
Inspection of sample of line for wall thickness by ultrasonic or comparable technique	1																			
Survey by inspection pig-magnetic flux type or other comparable device	a. 0.25			X							X				X					
	b. 0.50															X		X		
	c. 1																			
Depth of cover inspection by sonar (sidescan and penetrating) or other comparable device-Underwater lines only	4							X						X				X	X	X
Charting of line pipe-Underwater lines only	0.5																	X	X	
Preventive program for outside forces (Reference 12) One-Call System	continuous		X							X	X	X	X		X	X	X			
Pig line for water removal	3^{2}																			

Notes:

1. Optional schedules to accomplish indicated percent reduction of frequency of spills are identified in columns (A, B, C,... etc.) below.
2. Frequency of inspection is assumed at three times per year.
3. Underwater lines only, however, other schedules shown may also apply.

EPA Form 2350-6 (4-80)

TYPING GUIDE SHEET

TABLE 81. PREVENTIVE MAINTENANCE SCHEDULES FOR THE REDUCTION OF THE VOLUME OF ACCIDENTAL SPILLS FROM LINE PIPE

Inspection and/or Leak Detection Methods	Inspection Frequency/Year	Percent Reduction of Volume of Spills																										
		>25% Schedule[1]											>50% Schedule[1]									>75% Schedule[1]						
		A	B	C	D	E	F	G	H	I	J[3]	K[3]	A	B	C	D	E	F	G[3]	H[3]	I[3]	A	B	C	D	E	F[3]	G[3]
Visual line inspection by air or ground patrol in excess of required inspections	a. 26																X					X						
	b. 338				X									X										X				
Visual inspection by ground patrol with hydrocarbon probe or comparable device for indication of spill (onland lines only)	a. 26																											
	b. 52																											
	c. 338																											
Hydrocarbon probe-towfish or similar device-underwater lines only	6										X								X								X	
Pressure deviations																												
a. Pump stations (existing method)	continuous																											
b. Along line	continuous																											
Flow rate																												
a. Deviations	continuous							X																				
b. Comparisons (computerized)	continuous									X																		
Volume comparisons (computerized)	continuous					X									X										X	X		
Mathematical modeling (computerized)	continuous			X									X										X					
Negative pressure surge (computerized)	continuous																											
Passive acoustic array (computerized)																												
a. Retrofit	continuous						X									X										X		
b. New line	continuous																											X
External rods with passive acoustic	after indication of spill[2]																											
Pressure static	after indication of spill[2]																											
Hydrostatic	a. 1																											
	b. 2																											
	c. after indication of spill[2]	X																X				X						
Pressure difference	a. 1																											
	b. 2																											
	c. 4																											
	d. 12																											
Change or add inhibitors as needed	3[2]																											
Inspection of sample of line for wall thickness by ultrasonic or comparable technique	1																											
Survey by inspection pig-magnetic flux type or other comparable device	a. 0.25								X										X		X							
	b. 0.50																											
	c. 1																											
Depth of cover inspection by sonar (sidescan and penetrating) or other comparable device-underwater lines only	4											X								X	X						X	X
Charting of line pipe-Underwater lines	0.5																											
Preventive program for outside forces (Reference 12) One-Call System	continuous		X														X	X	X			X		X	X	X		
Pig line for water removal	3[2]																											
Oil spill detectors-Marine terminal, etc.	continuous																											

Notes. 1. Optimal schedules to accomplish indicated percent reduction of volume of spills are identified in columns (A, B, C,...etc.) below.
2. Frequency of inspection is assumed at three times per year.
3. Underwater lines only, however, other schedules shown may also apply.

EPA Form 2350-4 (4-80)
TYPING GUIDE SHEET

TABLE 82. PREVENTIVE MAINTENANCE SCHEDULES FOR THE REDUCTION OF THE FREQUENCY AND VOLUME OF ACCIDENTAL SPILLS FROM LINE PIPE

Inspection and/or Leak Detection Methods	Inspection Frequency/ Year	Percent Reduction of Volume of Spills																	
		>25% Schedule[1]								>50% Schedule[1]							>75% Schedule[1]		
		A	B	C	D	E	F	G[3]	H[3]	A	B	C	D	E	G[3]	H[3]	A	B	C
Visual line inspection by air or ground patrol in excess of required inspections	a. 26								X	X	X	X					X	X	X
	b. 338				X														
Visual inspection by ground patrol with hydrocarbon probe or comparable device for indication of spill (onland lines only)	a. 26																		
	b. 52						X						X						
	c. 338																		
Hydrocarbon probe-towfish or similar device-Underwater lines only	6								X						X	X			
Pressure deviations																			
a. Pump stations (existing method)	continuous																		
b. Along line	continuous																		
Flow rate																			
a. Deviations	continuous																		
b. Comparisons (computerized)	continuous																		
Volume comparisons (computerized)	continuous													X			X	X	
Mathematical modeling (computerized)	continuous											X				X			
Negative pressure surge (computerized)	continuous																		
Passive acoustic array (computerized)																			
a. Retrofit	continuous					X							X						X
b. New line	continuous																		
External rods with passive acoustic	after indication of spill[2]																		
Pressure static	after indication of spill[2]																		
Hydrostatic	a. 1																		
	b. 2																		
	c. after indication of spill[2]	X								X							X		
Pressure difference	a. 1																		
	b. 2																		
	c. 4																		
	d. 12																		
Change or add inhibitors as needed	3[2]																		
Inspection of sample of line for wall thickness by ultrasonic or comparable technique	1																		
Survey by inspection pig-magnetic flux type or other comparable device	a. 0.25			X							X			X	X				
	b. 0.50																	X	
	c. 1																		
Depth of cover inspection by sonar (sidescan and penetrating) or other comparable device-Underwater lines only	4							X							X	X			
Charting of line pipe-Underwater lines	0.5																		
Preventive program for outside forces (Reference 12) One-Call System	continuous		X							X	X	X	X	X			X	X	X
Pig line for water removal	3[3]																		
Oil spill detectors-Marine terminal, etc.	continuous																		

Notes:
1. Optimal schedules to accomplish indicated percent reduction of volume of spills are identified in columns (A, B, C....etc.) below.
2. Frequency of inspection is assumed at three times per year.
3. Underwater lines only, however, other schedules shown may also apply.

BEGIN FIRST LINE OF TEXT HERE
CENTER OF PAGE
TOP OF IMAGE AREA
DROPPED HEAD; BEGIN SECTIONS HERE
BEGIN LAST LINE OF TEXT
3/8"
PAGE NUMBER
BOTTOM OF IMAGE AREA; OUTSIDE DIMENSION OF TABLES AND ILLUSTRATIONS
EPA Form 2350-4 (4-80)
(PREVIOUSLY CIN. EPA FORM 382)
TYPING GUIDE SHEET

Implementation of the One-Call System as recommended in Reference 12 is expected to result in annual savings of approximately 120,000 barrels of petroleum (40 percent of total). This is also expected to decrease the number of incidents by 88 (33 percent of total).

Survey of the line by inspection pigs (magnetic flux type or other comparable device) carried out every four years is expected to save approximately 80,000 barrels of petroleum (28 percent of total) and decrease the number of incidents by 106 (36 percent of total). This inspection would be particularly effective in preventing spills caused by line pipe faults.

Hydrostatic tests are recommended for lines where inspection pig surveys are impractical because of line pipe size or other considerations. Either yearly tests or tests after indication of a spill (whichever schedule is most effective) are recommended. These inspections are expected to save approximately 60 to 90 thousand barrels of petroleum (20 percent to 33 percent of the total) and decrease the number of incidents by 80 to 100 (28 percent to 35 percent of the total).

Overall, these inspections are expected to reduce the spill volume and spill incidents by more than 66 percent. Total costs are estimated at less than 40 million dollars per year. This cost is significantly lower than the cost of preventive maintenance using cathodic protection systems. Yet, the reduction of the number of incidents and spill volume is expected to be much greater.

8.3.3.2 Underwater Lines--

Recommendations for underwater lines include:

- Visual inspections of the line by air or ground patrol - weekly
- Depth of cover inspection by sonar or other comparable device - every two years
- Hydrocarbon probe (towfish or similar device) inspection - yearly
- Survey by inspection pig (magnetic flux type or other comparable device) - every two years

or

- Hydrostatic test - yearly.

(See also developmental and new methods Section 8.4).

8.3.3.3 Large Diameter Lines--

Recommendations for large diameter lines (greater than 16 inches in diameter) include:

- Visual inspections by air or ground patrol - weekly
- One-Call System (Reference 12)

EPA Form 2350-4 (4-80)
TYPING GUIDE SHEET

- Survey by inspection pig (magnetic flux type or other comparable device) - every four years
- Volume comparison, flow rate comparison and pressure deviation

or

- Mathematical modeling.

(See also developmental and new methods Section 8.4).

8.3.3.4 Old Lines--

Recommendations for old lines (30 years or older) include:

- Visual inspections by air or ground patrol - weekly
- One-Call System (Reference 12)
- Survey by inspection pig (magnetic flux type or comparable device) - every three years

or

- Hydrostatic tests
  - yearly, or
  - after indication of spill.

8.3.3.5 Lines with Two or More Reportable Spill Incidents within One Year--

Recommendations for lines with two or more reported spill incidents within one year include:

- Visual inspection by air or ground patrol - weekly
- One-Call System (Reference 12)
- Survey by inspection pig (magnetic flux type or comparable device) - every year
- Hydrostatic tests - yearly.

This schedule should be in effect until approximately three years after spill incidents are reduced to a normal rate.

8.4 RECOMMENDED DEVELOPMENTAL AND NEW INSPECTION AND LEAK DETECTION METHODS

Although a number of developmental and new inspection and leak detection methods are capable of reducing the potential of spills, only a few are considered to have the potential of significantly reducing the oil spill risk. These include:

- Mathematical modeling
- Passive acoustic array
    - retrofit (prevent damage from outside forces)
    - new lines (prevent damage and detect failures).

Mathematical modeling of the line appears to be a proven new technique but should be thoroughly reviewed and evaluated before it can be recommended for most lines. It is recommended at this time for use on lines that are in high risk areas, such as underwater lines, and/or lines with a high risk that oil may escape from a line such as those of large diameter. The method, if used alone, is expected to reduce the expected volume of spills by about 65 percent. It also appears to be one of the most cost-effective methods available (see Table 78). No conclusive evidence is available to prove that the method can prevent spills, although such events as line pressure surges may be reduced with this method. The method should be considered with other options, particularly ones that prevent spills. Use of this method on a large number of lines would be difficult to implement at this time because only a few small sized commercial companies and a few oil companies are actively involved in this area.

The passive acoustic array system for retrofitting on existing lines is a developmental method that shows promise for most lines. It is recommended that this method be investigated further to verify its capability of preventing damage from outside forces and rupture detection. The method, if used alone, is expected to reduce the frequency of spills by about 30 percent and the volume of spills by about 70 percent. The method appears to be one of the most cost-effective methods available (see Table 78).

The passive acoustic array system for new lines is a developmental method that is attractive for lines in certain high risk areas, i.e., underwater lines, populated areas, etc. It is recommended that this method be investigated further to verify its capability to both prevent failure from outside forces and other causes and detect leaks. The method, if used alone, is expected to reduce the frequency of spills by about 43 percent and the volume of spills by about 84 percent. Since the method appears to be of relatively low cost-effectiveness, its application should be limited to lines in high risk areas.

REFERENCES

1. Pipeline Safety Need for a Stronger Federal Effort. PB-280321, U.S. General Accounting Office, 1975.

2. Leggett, N., and M. Placet. A Comparison of National Air Residual in NEDS and SEAS. Working Paper IR&T-18, International Research and Technology Corp., 1978.

3. Crude Petroleum, Petroleum Products and Natural Gas Liquids in the U.S. Annual Reports. U.S. Department of Interior (Bureau of Mines), 1971-1977.

4. Hittman Associates, Inc. Environmental Impacts, Efficiency, and Cost of Energy Supply and End Use. Volume 1. PB 238-784. Council on Environmental Quality, Washington, D.C., 1974.

5. Association of Oil Pipelines. Press Release. June 7, 1975: May 26, 1975.

6. Transport Statistics in the U.S., Part 6, Oil Pipeline. Annual Reports. Interstate Commerce Commission (Bureau of Accounts). 1965-1976.

7. Regulations on Transportation of Liquids by Pipeline. Title 49 of Code of Federal Regulations, Part 195. Department of Transportation, 1977.

8. Petroleum Extension Service. Introduction to the Oil Pipeline Industry. The University of Texas, Austin, Texas, 1966. 84 pp.

9. Mineral Industry Surveys: Crude Oil and Refined Products Pipeline Mileage in the United States. U.S. Department of Interior (Bureau of Mines), 1971.

10. Mineral Industry Surveys: Crude Oil and Refined Products Pipeline Mileage in the United States. U.S. Department of Interior (Bureau of Mines), 1974.

11. Energy Data Reports: Crude Oil and Refined Products Pipeline Mileage in the United States. U.S. Department of Energy (Bureau of Mines), 1977.

EPA Form 2350-4 (4-80)

TYPING GUIDE SHEET

12. Courtney, W.J., G. Yie, and D. Kalbbrenner. Effectiveness of Programs for Prevention of Damage to Pipelines by Outside Forces. Report DOT/MTB/OPSO-77/12, ITT Research Institute, 1977.

13. Petroleum Storage Capacity, National Petroleum Council, 1974.

14. Mastandrea, J.R., J.A. Simmons, P.B. Kimball, and K.J. Gilbert. Deep-water Port Inspection Methods and Procedures. Report No. CG-D-31-78, United States Coast Guard, Department of Transportation, 1978.

15. Volumetric Shrinkage Resulting from Blending Volatile Hydrocarbons with Crude Oils. Bull. API 2509C. American Petroleum Institute, Washington, D.C., 1967.

16. Lease Automatic Custody Transfer. Bull. API Standard 2502. American Petroleum Institute, Washington, D.C., 1967.

17. Brooks - Bi Rotor Meters. Bulletin (S)DS-(B-42DEB). Brooks Instrument Division, Emerson Electric Company, 1978.

18. Smith-Meter Systems. Bulletin 271. A. O. Smith Company.

19. Karabelas, A.J. Recent Studies Improve Velocity Criteria Used for BS&W Sampling. Oil and Gas Journal, April 17, 1978. pp. 98-104.

20. Reproducibility Between Laboratories. ASTM Standard D 287.

21. Lipkin, M.R. and S.S. Kurtz. Temperature Coefficient of Density and Refractive Index for Hydrocarbons. Ind. Eng. Chem. Anal., Ed. 13, 1941. pp. 291-295.

22. Downer, J.L. and F.A. Inkley. Need Shown for Separate Thermal-Expansion Tables. Oil and Gas Journal 70:25, June 19, 1972. pp. 52.55.

23. Form P--Pipe Line Operation Expenses for Carrier Pipe Line Companies in the U.S. Annual Reports. Interstate Commerce Commission (Bureau of Accounts), 1965-1976.

24. Capital Systems. Digest of Pipeline Rates on Gasoline and Petroleum. Capital Systems Publications, Rockville, MD, Annual Report.

25. Liquid Pipeline Accidents Reported to the Department of Transportation on DOT Form 7000-1. Annual Reports. Department of Transportation (Office of Pipeline Safety), 1969-1977.

26. Ulrich, L. Detailed Information for Each Accident During the Period 1971 through 1975. Office of Pipeline Safety, 1977.

27. Danenberger, E.P. Oil Spills, 1971-1975, Gulf of Mexico Outer Continental Shelf. Circular 741. U.S. Geological Survey, 1976.

28. Conservation Division. Accidents Connected with Federal Oil and Gas Operations on the Outer Continental Shelf. U.S. Geological Survey, Conservation Division, 1977.

29. Pollution Incidents in and Around U.S. Waters. U.S. Coast Guard Publication, Pollution Incident Reporting System (PIRS). CG-487. 1975 and 1976.

30. Ritchie, J.E., Jr., et al. Petroleum System Reliability Analysis. Volume I and II. Report No. EPA-R2-73-820b, U.S. Environmental Protection Agency, Washington, D.C., 1973.

31. Leo, J.E. and G.G. Kruijer. Spillages from Oil Industry Cross-Country Pipelines in Western Europe, Statistical Summary of Reported Incidents, 1966-1969. Stichting CONCAWE Oil Pipelines Working Group, 1971.

32. King, E.M. and G.G.Kruijer. Spillages from Oil Industry Cross-Country Pipelines in Western Europe, Statistical Summary of Reported Incidents, 1971. Stichting CONCAWE Oil Pipelines Advisory Group, 1972.

33. King. E.M. and P. Rogier. Spillages from Oil Industry Cross-Country Pipelines in Western Europe, Statistical Summary of Reported Incidents, 1972. Stichting CONCAWE Oil Pipelines Special Task Force 1, 1973.

34. King, E.M. and P. Rogier. Spillages from Oil Industry Cross-Country Pipelines in Western Europe, Statistical Summary of Reported Incidents, 1973. Stichting CONCAWE Oil Pipelines Special Task Force 1, 1974.

35. King, E.M. and P. Rogier. Spillages from Oil Industry Cross-Country Pipelines in Western Europe, Statistical Summary of Reported Incidents, 1974. Stichting CONCAWE Oil Pipelines Special Task Force 1, 1975.

36. King, E.M. and P. Rogier. Spillages from Oil Industry Cross-Country Pipelines in Western Europe, Statistical Summary of Reported Incidents, 1975. Stichting CONCAWE Oil Pipelines Special Task Force 1, 1976.

37. King, E.M. and V. Baradat. Spillages from Oil Industry Cross-Country Pipelines in Western Europe, Statistical Summary of Reported Incidents, 1976. Stichting CONCAWE Oil Pipelines Special Task Force 1, 1977.

38. Mackay, D., et al. The Physical Aspects of Crude Oil Spills on Northern Terrain. Task Force on Northern Oil Development. Report 73-42; Information Canada Catalog R72-9173, 1974.

39. Beyer, A.H. and L.J. Painter. Estimating the Potential for Future Oil Spills from Tankers, Offshore Development and Onshore Pipelines. In: Proceedings of the 1977 Oil Spills Conference, Prevention, Behavior, Control, Cleanup. Am. Petroleum Institute, U.S. Environmental Protection Agency, and the U.S. Coast Guard, New Orleans, LA, 1977.

EPA Form 2350-4 (4-80)
(PREVIOUSLY CIN. EPA FORM 241)
TYPING GUIDE SHEET

40. Stewart, Robert J. The Tanker/Pipeline Controversy. Proceedings of the 1977 Oil Spills Conference; Prevention, Behavior, Control, Cleanup, Petroleum Institute, U.S. Environmental Protection Agency, and the U.S. Coast Guard, New Orleans, LA, 1977. pp. 95-99.

41. Operations Research, Inc. Spill-Risk Analysis Program: Interim Report E-2: Facilities Analysis, 1975.

42. Young, G.K., D. Evans, and R.U. Jettmar. Analysis of Oil Spill Trends. Report to the Council of Environmental Quality, Alexandria, VA, 1976.

43. Bayaert, Bruce. Analysis of Oil Spill Accidents for Environmental Impact Statements. In: Proceedings of the Conference on Prevention and Control of Oil Pollution. American Petroleum Institute, U.S. Environmental Protection Agency, and U.S. Coast Guard, San Francisco, CA, 1975. pp. 39-45.

44. Paulson, A.S., A.D. Schumaker, and W.A. Wallace. A Risk-Analysis Approach to Control of Large-Volume Oil Spills. In: Proceedings of the Conference on Prevention and Control of Oil Pollution. American Petroleum Institute, U.S. Environmental Protection Agency, and the U.S. Coast Guard, San Francisco, CA, 1975. pp. 301-106.

45. Wilson, J.D. A Statistical Estimate of Pipeline Leakage. Report SAI-79-162. Santa Ana, CA, 1977.

46. Colburn, C. Methods of Preventing, Detecting and Dealing with Surface Spills of Contaminants which may Degrade Underground Water Sources. Report EPA 68-01-4620, U.S. Environmental Protection Agency, Office of Water Supply, Washington, D.C., 1978.

47. Boyd, B.D., C.C. Bates, and J.R. Harrald. The Statistical Picture Regarding Discharges of Petroleum Hydrocarbons in and Around United States Water. Sources, Effects and Sinks of Hydrocarbons in the Aquatic Environment. In: Proceedings of the Symposium, American Institute of Biological Sciences, American University, Washington, D.C., 1974. pp. 38-53.

48. Petroleum in the Marine Environment. National Academy of Sciences, 1975.

49. Kiefner, J.R. and R.B. Smith. An Analysis of Reportable Incidents for Natural Gas Transmission and Gathering Lines, 1970 through 1975. Report NG-18, Report No. 106 to the Pipeline Research Committee, American Gas Association, 1977.

50. Marine Environmental Protection Program: An Analysis of Mission Performance. United States Coast Guard, Department of Transportation, Washington, D.C. 1975.

EPA Form 2350-4 (4-80)
TYPING GUIDE SHEET

BEGIN FIRST LINE OF TEXT HERE
CENTER OF PAGE
TOP OF IMAGE AREA

7

51. Funge, W.J., K.S. Change, D.I. Juran, et al. Offshore Pipeline Safety Practices, Volume II - Main Text. Report DOT/MTB/OPSA-77/14, 1977.

52. Jones, S.C. and Roszelle, W.D. Graphical Techniques for Determining Relative Permeability from Displacement Experiments. Journal of Petroleum Technology, 1978.

53. Blocker, P.C. Migration of Oil in Soil. Paper Presented at International Conference, "Antinguinamento 71," 1971.

54. Dan J. Van. The Migration of Hydrocarbons in a Water Bearing Stratum Of Stichting CONCAWE, The Hague, 1966.

55. Duffy, J., M.F. Mohtadi and E. Peaka. Subsurface Persistance of Crude Oil Spilled on Land and Its Transport in Groundwater. Proceedings 1977 Oil Spill Conference. American Petroleum Institute, U.S. Environmental Protection Agency, and U.S. Coast Guard, New Orleans, LA, 1977.

56. The Migration of Petroleum Products in Soil and Groundwater. Publication No. 4149, American Petroleum Institute, Washington, D.C., 1972.

57. Goodfellow, R. Underwater Engineering. Tulsa, OK, 1977.

58. Platus, D.L., et al. Rapid Shutdown of Failed Pipeline Systems and Limiting of Pressure to Prevent Pipeline Failure Due to Overpressure. Report PB 241-325, U.S. Department of Transportation, 1974.

59. McFarlane, C. and R.D. Watson. The Detection and Mapping of Oil on a Marshy Area by a Remote Luminescent Sensor. Proceedings 1977 Oil Spill Conference. American Petroleum Institute, U.S. Environmental Protection Agency, and U.S. Coast Guard, New Orleans, LA, 1977.

60. Jackson, P. Leak Detection in Underwater Oil Pipelines. Report NMRC 272-23100-R2, National Maritime Research Center, 1973.

61. Oil Pollution Detection and Sensing - Bibliography with Abstracts. Search Period 1964-July 1976. Report NTIS/PS-76-0701, NTIS, 1976.

62. Rambie, G.J., Jr., R.H. Morgan and R.J. Jones. Feasibility of Continuous Monitoring for Oil Pollution Across Channels and Rivers. Proceedings 1977 Oil Spills Conference, Prevention, Behavior, Control, Cleanup, American Petroleum Institute, U.S. Environmental Protection Agency, and U.S. Coast Guard, New Orleans, LA, 1977.

63. Alford, B.J., M.M. Paterson, and F.A. Womack. Development and Field Evaluation of the Production Surveillance Monitor. Journal of Petroleum Technology, 1978.

64. Jouve, P. Process and Apparatus for Detecting a Fluid Leak from a Pipeline. Belgian Patent No. 823,862, 1977.

DROPPED HEAD; BEGIN SECTIONS HERE
BEGIN LAST LINE OF TEXT
BOTTOM OF IMAGE AREA OUTSIDE DIMENSION FOR TABLES AND ILLUSTRATIONS
3/8"

PAGE NUMBER
EPA Form 2350-4 (4-80)
(PREVIOUSLY CIN. EPA FORM 287)
TYPING GUIDE SHEET

65. Holland, W.E. and G.R. Burrell. Acoustic Method for Detecting Leaks from Submerged Pipelines. U.S. Patent No. 4,001,769, 1977.

66. Ells, J.W. and A. Roberts. Underwater Pipelines. U.S. Patent No. 3,992,924, 1976.

67. Boyens, V.C. Pipeline Leak Locator Method. U.S. Patend No. 4,016,748, 1977.

68. Bielawa, R. and H. Howe. Radar Unit Locates Buried Plastic and Metal Lines. Pipeline Industry, July 1977.

69. Farmer, W.M., et al. Feasibility of Scour Monitoring. Report 1-SAI-75-503-77, U.S. Department of Transportation, Washington, D.C., 1975.

70. Mastandrea, J.R. and J.M. Zuieback. Feasibility of Scour Monitoring Instrumentation. Report SAI-260-76-518-LA for U.S. Department of Transportation, Washington, D.C., 1976.

71. Underwater Inspection/Testing/Monitoring of Offshore Structures. Conducted by R. Frank Busby Associates. Sponsored by DOT, DOE and DOI, Contract 7-35336, February 1978.

72. Los Angeles Times.

73. Philpot, F.V. and A.D. Higham. Pig and Leak Location Undersea Pipe Lines. Presented to the Oceanology International Conference, Brighton, England, 1978.

74. These Inspection Probes Check Internal Rise Corrosion. Ocean Industry, February 1978.

75. Ultrasonic Rises Inspection Tool Successful. Ocean Industry, August 1978.

76. Metzler, J.A. Acoustic Holography may Permit Buried Pipe Line Inspection. Ocean Industry, May 1978.

77. Dodd, V.R. Integrated Machinery Inspection Program Cuts Maintenance Costs. Oil and Gas Journal, April 1978.

78. Boorman, R.D. and A.R. Walledge. Current Method of Routine Testing and Leak Detection in Operating Oil Line. Report No. 5/73, Stichting CONCAWE, The Hague, 1973.

79. Catagnet, A.C. Application of Radioisotopes in Oil, Gas and Petrochemical Industries - Transport of Hydrocarbons. Instituto de Energia Atomica, Sao Paulo (Brazil). Div. de aplicacao de Radioisotopos na Engenharis e na Industria, August 1976.

EPA Form 2350-4 (4-80)
(PREVIOUSLY CIN. EPA FORM 287)
TYPING GUIDE SHEET

80. Published Regulatory Guidelines of Environmental Concern to the Oil Industry in Western Europe. CONCAWE Report No. 2/77.

81. Baker, J.M. Marine Ecology and Oil Pollution: The Work of the Oil Pollution Research Unit.

82. Annual Report to Congress by National Transportation Safety Board, U.S. Government Printing Office, Stock No. 5000-00084, 1975.

83. Dubiel, E.J. The Practical Aspects of Litigating an Oil Spill (Plaintiff's Viewpoint). Proceedings 1979 Oil Spills Conference, American Petroleum Institute, U.S. Environmental Protection Agency, and U.S. Coast Guard, Los Angeles, CA, 1979.

EPA Form 2350-4 (4-80)
(PREVIOUSLY CIN. EPA FORM 287)
TYPING GUIDE SHEET

BEGIN FIRST LINE OF TEXT HERE
CENTER OF PAGE
TOP OF IMAGE AREA
DROPPED HEAD; BEGIN SECTIONS HERE

APPENDIX A

EXISTING U.S. AND FOREIGN REGULATIONS FOR TRANSPORTATION OF LIQUIDS BY PIPELINE

A.1 TITLE 49-U.S. TRANSPORTATION OF LIQUIDS BY PIPELINES

TITLE 49 PART 145
A.1. TITLE 49-U.S. TRANSPORTATION OF LIQUIDS BY PIPELINES

DEPARTMENT OF TRANSPORTATION
MATERIALS TRANSPORTATION BUREAU
WASHINGTON, D.C. 20590

Title 49—Transportation

CHAPTER I—MATERIALS TRANSPORTATION BUREAU, DEPARTMENT OF TRANSPORTATION

SUBCHAPTER B—OFFICE OF PIPELINE SAFETY OPERATIONS

[Amdt. 192-28; Docket No. OPSO-37]

PART 192—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE

Corrosion Control for Metal Alloy Fittings in Plastic Pipelines

AGENCY: Materials Transportation Bureau, Office of Pipeline Safety Operations, Department of Transportation.

ACTION: Final rule.

SUMMARY: This amendment permits the use of certain metal fittings in plastic pipelines without coating, cathodic protection, and monitoring when adequate external corrosion control is provided by alloyage. The full safety and economic advantage of these fittings cannot be realized under the present rule because of the cost and burden of providing cathodic protection and frequent monitoring.

EFFECTIVE DATE: This amendment becomes effective on August 12, 1977.

FOR FURTHER INFORMATION CONTACT:

Ralph T. Simmons (202-426-2392).

SUPPLEMENTARY INFORMATION: On September 22, 1976, the Materials Transportation Bureau (MTB) issued a notice of proposed rulemaking, Notice No. 76-1, (41 FR 42221, September 27, 1976), to exempt certain alloy fittings installed in plastic pipelines from the external corrosion control requirements of § 192.455. To qualify for exemption, it was proposed that the fittings be small, electrically isolated, and designed to prevent leakage caused by localized corrosion pitting, and that the operator demonstrate that adequate corrosion control is provided by alloyage. Interested persons were invited to submit written data, views, or arguments by November 1, 1976.

There were 24 persons who submitted written comments to Notice No. 76-1: 19 natural gas distribution companies, 3 state regulatory agencies, 1 trade association, and 1 manufacturer of fittings. All 24 commenters were favorable, in general, to the proposed amendment. A discussion of the significant comments which suggested that changes be made to the proposed amendment and the disposition of those comments in developing the final rule is contained in the "Discussion of the Comments" section of this preamble. Comments which suggested rule changes outside the scope of the proposed notice are not discussed but may be considered by the Materials Transportation Bureau (MTB) in any future rulemaking on corrosion control. Also, editorial changes in the final rule which do not alter the substance of the proposal are not discussed herein.

Discussion of comments. With regard to the term "small" in the proposed § 192.455(f), five commenters suggested that it either be deleted or defined since the term "small" without definition would be open to individual interpretation and could result in a nonuniform application of the regulations. Alternatively, these commenters suggested that the size of the fittings be limited to six inches or less in diameter and 12 inches or less in length. The commenters contend that such size would be sufficiently small to protect against electrolytic corrosion provided a fitting is electrically isolated. Five other commenters stated that any exemption of fittings should not be restricted by size. These commenters suggested that such a restriction would be unnecessary in view of the size limitations effectively placed on the use of plastic pipe in gas service by the available joining methods and by the cost of materials. (Presently, 12-inch diameter plastic pipe is the largest normally used in gas service.) These commenters also pointed out that the most relevant test of safety would be meeting the proposed requirement to demonstrate that corrosion is not a problem. Further, on this point, the Technical Pipeline Safety Standards Committee (TPSSC) stated that a size limitation might restrict the application of new technology and that adequate protection would be provided by requiring the operator to show by tests, investigation, or experience that adequate corrosion control is obtained through alloyage.

In the Notice, MTB noted that the term "small" is rather indefinite and requested specific comments on adoption of the term or any comparable restriction in the final rule. The term was included in the Notice because of evidence indicating that small components are not as susceptible to corrosion as larger ones. However, after considering all relevant information, MTB now believes that adoption of the term "small" could result in nonuniform application of § 192.455 and has deleted it in the final rule. Also, a size limitation is effectively created by present technology and economics related to the use of plastic pipe.

BEGIN LAST LINE OF TEXT
3/8"
BOTTOM OF IMAGE AREA OUTSIDE DIMENSION FOR TABLES AND ILLUSTRATIONS

PAGE NUMBER
EPA Form 2350-4 (4-80)
(PREVIOUSLY CIN. EPA FORM 3??)
TYPING GUIDE SHEET

More significant than size, however, in protecting against corrosion is the fact that as discussed hereafter the operator would be required under § 192.455 (f)(1) to show by tests, investigation, or experience that adequate corrosion control is provided by alloyage of the fitting material. To ensure that this restriction is appropriately applied in view of the deletion of the word "small," in the final rule, the proposed § 192.455(f)(1) is modified by the phrase "for the size of fitting to be used." This modification is consistent with a change recommended by the TPSSC.

Twelve commenters and the TPSSC felt that the word "metallic" should be substituted in the final rule for the word "alloy" used in the proposal. These commenters contend that metals other than Type 316 stainless steel are corrosion resistant and could do an equally satisfactory job in protecting against corrosion. Although the petition upon which Notice 76-1 was based referred to Type 316 stainless steel fittings, the proposed amendment was written to provide for the use of any alloy material that can provide the necessary corrosion resistance. Therefore, MTB has not adopted this proposed word change in the final rule. Also, in this regard, the TPSSC suggested that the word "fitting" be replaced by "component." This comment was not adopted, however, because the word "component" has a broader connotation than was intended by use of the word "fitting" in the Notice.

Five other commenters and the TPSSC suggested that the words "by alloyage" in the proposed § 192.455(f)(1) should be omitted. They argue that subparagraph (f)(1) would establish a good performance standard without the words "by alloyage" since the most important consideration is prevention of corrosion failures. Although this argument may be true, this comment was not adopted because the word "alloyage" is necessary to provide a definitive description of the type of corrosion control which is intended to qualify fittings for an exemption under § 192.455(f).

Nine commenters suggested that the proposed limitation under § 192.455(f)(2) (that a fitting be designed to prevent leakage due to corrosion pitting) either be deleted or adopted as an alternative to the proposed restriction of § 192.455(f)(1). Three commenters contended that in complying with either subparagraph (f)(1) or (f)(2), the corrosion problem is resolved.

MTB does not agree with these comments and for the following reasons did not adopt them in the final rule. Considering the lack of performance data available for the alloy fittings which might be used to qualify for an exemption from the cathodic protection and coating requirements of § 192.455(a), the variable corrosivity conditions in which fittings might be installed, and imprecise corrosivity measurement techniques available, MTB believes that an initial determination of the protection afforded by alloyage may not provide a sufficient, long-term safeguard against corrosion. As an additional factor in providing long-term protection, MTB believes that the fitting must also be "designed" to prevent any leakage that may be caused by localized corrosion.

Furthermore, for these same reasons relating to the possible uncertainty of future corrosion control performance, the final rule is changed by adding a subparagraph (f)(3) to require that each operator be able to identify the location of each fitting installed under § 192.455 (f). This additional requirement appears necessary to protect the public interest, and it is consistent with the requirement of § 192.491 that an operator know the location of all cathodically protected piping. Subparagraph (f)(3) is intended to provide for any future inspection, repair, or replacement that might be required as a result of future rulemaking should any new information indicate a need for such remedial action.

In addition, MTB requests that operators voluntarily report the condition of any alloy fitting installed under § 192.455 (f) which is uncovered for any reason. MTB is interested in receiving reports on corrosion performance of the fittings, especially any leakage of a fitting that is not required to be reported under §§ 191.5 and 191.9 of this chapter, and the number of fittings installed. These reports could be submitted by operators in letter form and need not be submitted more often than once a year, unless the operator desires to report more frequently. MTB expects that information obtained through the voluntary reporting may serve as a basis for a future rulemaking action either to relax the restrictions applicable to exemption under § 192.455(f) or to prescribe any necessary remedial measures, as the case may be.

BEGIN FIRST LINE OF TEXT HERE
CENTER OF PAGE
TOP OF IMAGE AREA
DROPPED HEAD: BEGIN SECTIONS HERE
BEGIN LAST LINE OF TEXT
3/8"
PAGE NUMBER
BOTTOM OF IMAGE AREA OUTSIDE DIMENSION FOR TABLES AND ILLUSTRATIONS
EPA Form 2350-8 (4-80)
(PREVIOUSLY CIN. EPA FORM 437)
TYPING GUIDE SHEET

BEGIN FIRST LINE OF TEXT HERE
CENTER OF PAGE
TOP OF IMAGE AREA
DROPPED HEAD, BEGIN SECTIONS HERE

Regarding the proposed § 192.455(f)(2), the TPSSC further suggested that the term "corrosion pitting" be replaced by "corrosion attack." This comment was not adopted for the sake of consistency since the term "corrosion pitting" is used elsewhere in Part 192.

Another commenter thought that an operator should not have to use tests, investigation, or experience "in the area of application" to show under § 192.455(f)(1) that alloy fittings provide adequate corrosion control. This commenter alleged that the testing, investigation, or experience in the corrosion studies reported in the National Bureau of Standard's (NBS) Circular No. 579 and two California field studies mentioned in the Notice are sufficient to allow a general exception without the need for an individual finding by each operator.

MTB does not agree. The NBS study compares the performance of certain materials under a limited number of environments. It did not establish a means to quantitatively measure the corrosivity of any environment in which a material might be used. Also, the two field studies conducted in California do not have universal application to all soils. Those studies are more indicative of local conditions. They include the type of testing and investigation that an operator might conduct in an area to determine whether fittings are adequately protected against corrosion by alloyage. For these reasons, MTB did not adopt the suggested change in the final rule.

REPORT OF THE TECHNICAL PIPELINE SAFETY STANDARDS COMMITTEE

Section 4(b) of the Natural Gas Pipeline Safety Act of 1968 requires that all proposed standards and amendments to such standards pertaining to gas pipelines be submitted to the Committee and that the Committee be afforded a reasonable opportunity to prepare a report on the "technical feasibility, reasonableness, and practicability of each proposal." The proposed amendment was submitted to the Committee as Item A-1 in a list of two proposed amendments at a meeting in Washington, D.C., on December 16 and 17, 1976. A minority report was not submitted.

On February 3, 1977, the Committee filed the following favorable report:

This communication is the official report of the Technical Pipeline Safety Standards Committee concerning the Committee's action on two amendments to 49 CFR Part 192 proposed by the Office of Pipeline Safety Operations and other matters which the Committee decided should be brought to the attention of the Department of Transportation.

The following described actions were taken by the Committee at a meeting held in Washington, D.C., on December 16 and 17, 1976.

Item A-1 of the agenda was a proposal by OPSO to revise § 192.455, External corrosion control. By an affirmative vote of 12-1 the Committee found that the following language for § 192.455 is technically feasible, reasonable, and practicable.

* * * * *

(The language suggested is adopted in the final rule except as discussed in the "Discussion of Comments Section" above.)

PRINCIPAL AUTHORS

Ralph T. Simmons, Regulations Specialist, George Mocharko, Staff Engineer, and Robert L. Beauregard, Attorney, Office of the General Counsel.

In consideration of the foregoing, § 192.455 of Title 49 of the Code of Federal Regulations is amended by amending paragraph (a) and adding a new paragraph (f) to read as follows:

§ 192.455 External corrosion control: buried or submerged pipelines installed after July 31, 1971.

(a) Except as provided in paragraphs (b), (c), and (f) of this section, each buried or submerged pipeline installed after July 31, 1971, must be protected against external corrosion, including the following:

* * * * *

(f) This section does not apply to electrically isolated, metal alloy fittings in plastic pipelines if—

(1) For the size fitting to be used, an operator can show by tests, investigation, or experience in the area of application that adequate corrosion control is provided by alloyage;

(2) The fitting is designed to prevent leakage caused by localized corrosion pitting; and

(3) A means is provided for identifying the location of the fitting.

(49 USC 1672; 49 CFR 1.53(a).)

Issued in Washington, D.C., on July 1, 1977.

ALAN A. BUTCHMAN,
Acting Director, Materials Transportation Bureau.

[FR Doc.77-19421 Filed 7-8-77;8:45 am]

BEGIN LAST LINE OF TEXT
3/8"
BOTTOM OF IMAGE AREA OUTSIDE DIMENSION FOR TABLES AND ILLUSTRATIONS

PAGE NUMBER
EPA Form 2550-4 (4-80)
(PREVIOUSLY EPA FORM 287)
TYPING GUIDE SHEET

BEGIN FIRST LINE OF TEXT HERE
CENTER OF PAGE
TOP OF IMAGE AREA
DROPPED HEAD: BEGIN SECTIONS HERE

DEPARTMENT OF TRANSPORTATION
MATERIALS TRANSPORTATION BUREAU
WASHINGTON, D.C. 20590

Title 49—Transportation

CHAPTER I—MATERIALS TRANSPORTATION BUREAU, DEPARTMENT OF TRANSPORTATION

SUBCHAPTER D—PIPELINE SAFETY

[Amdts. 192–29; 195–12; Docket No. OPSO–38]

PART 192—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE

PART 195—TRANSPORTATION OF LIQUIDS BY PIPELINE

Longitudinal Seams in Pipe Bends

AGENCY: Materials Transportation Bureau, Department of Transportation.

ACTION: Final rule.

SUMMARY: This amendment permits longitudinal welds in field bends of steel pipe to be placed other than near the neutral axis when an internal bending mandrel is used or when bending pipe of 12 inches or less in outside diameter that has a diameter to wall thickness ratio of less than 70. This amendment permits the utilization of new techniques for bending steel pipe in the field and permits the realization of the attendant safety and economic benefits.

EFFECTIVE DATE: The effective date is October 3, 1977, except that § 192.313 (a)(4)(B) and § 195.212(b)(3)(B) do not become effective until November 3, 1977.

ADDRESS: Any person desiring to comment on Section 192.313(a)(4)(B) or Section 195.212(b)(3)(B) should comment in writing to:

Director, Office of Pipeline Safety Operations, Department of Transportation, 2100 Second Street, S.W., Washington, D.C. 20590.

Comments will be available at Docket Room 6500, 2100 Second Street, S.W., Washington, D.C.

FOR FURTHER INFORMATION CONTACT:

Ralph T. Simmons, (202) 426–2392.

SUPPLEMENTARY INFORMATION: The Materials Transportation Bureau (MTB) issued a notice of proposed rulemaking, Notice No. 76–2 (41 FR 46463, October 21, 1976), proposing to amend § 192.313(a)(4) of the Federal gas pipeline safety standards and § 195.212(b)(3) of the Federal liquid pipeline safety standards to permit the field bending of steel pipe with longitudinal welds without placing the longitudinal weld near the neutral axis of the bend if an internal bending mandrel is used. Interested persons were invited to participate in this rulemaking action by submitting written data, views, or arguments not later than November 8, 1976.

There were six persons who responded and submitted written comments to Notice 76–2. Three were from gas distribution companies and three were from trade associations. A discussion of the significant comments and the recommendations of the Technical Pipeline Safety Standards Committee (TPSSC) on the proposed amendment to Part 192 and their disposition in developing the final rules are contained in the following discussion of comments.

DISCUSSION OF COMMENTS

All of the commenters and the TPSSC supported the proposal as published in the Notice. Their reasons were that the improvements in pipe manufacturing methods and construction techniques, particularly with the use of the internal bending mandrel, have made the restriction on location of the longitudinal weld in a bend unnecessary. They concluded that operators and carriers should be allowed to utilize this improved technology that has demonstrated its ability to produce a high quality pipeline and shown the old requirement to be obsolete.

MTB agrees with the commenters and the TPSSC, that operators should be allowed to take full advantage of improved welding and bending technology that is not inconsistent with pipeline safety. After considering all available information, MTB is not aware of any failures in the longitudinal weld seam of pipe caused by bending with the longitudinal weld seam placed other than near the neutral axis. Additionally, MTB is of the opinion that the performance requirements in §§ 192.313 and 195.212 are sufficient to ensure that any pipe with a damaged weld seam would be detected and rejected before being placed in service. The advances in pipe manufacturing and bending methods make the requirement for placing the longitudinal weld in a neutral axis when bending with an internal bending mandrel unnecessary. The relaxation of the requirement would not be inconsistent with pipeline safety. Therefore, the proposed amendments have been adopted in the final rules as §§ 192.313(a)(4)(A) and 195.212(b)(3)(A).

One commenter agreed with the proposal as written, but recommended that MTB continue its investigation to substantiate the need for the requirement that a longitudinal weld be placed near the neutral axis during bending when an internal bending mandrel is not used. The reason given was that the proposal will provide the operator with a choice of methods for field bending of pipe.

MTB will continue its investigation and welcomes the submission of information from knowledgeable sources. Such information will be considered by MTB for future rulemaking proceedings on pipe bending.

Three commenters and the TPSSC suggested that an internal bending mandrel is inappropriate for bending small pipe, and use of the mandrel should not be adopted as a condition to not placing the longitudinal seam near the neutral axis. Their argument was that for large diameter pipe the requirement for using an internal bending mandrel is not unreasonable because internal bending mandrels are required to obtain acceptable field bends. However, for small diameter pipe, particularly 12 inches and under with a diameter to wall thickness (D/t) ratio of less than 70, internal bending mandrels are not needed to achieve acceptable bends. They further stated that, when using electric resistance welded pipe that has been weathered, cleaned, and coated, it is very difficult to locate the longitudinal weld seam.

After reviewing the comments, the TPSSC's recommendation, and other available information, MTB believes that safe bends in steel pipe 12 inches or less in outside diameter with a D/t ratio of less than 70 can be made without using an internal bending mandrel even though the longitudinal seam is not placed near the neutral axis of the bend. Further, MTB has not received any reports of failure of bent pipe of 12-inch diameter or less with a D/t ratio of less than 70 that can be attributed to the fact that an internal bending mandrel was not used or that the location of the longitudinal weld seam in bending was a contributing factor.

Therefore, in view of the favorable information and the absence of any information to the contrary, MTB is of the opinion that omitting the proposed condition that an internal bending mandrel be used when bending pipe of 12 inches or less in outside diameter with a D/t ratio less than 70 as an alternative to placing the weld seam near the neutral axis is not contrary to the public interest nor inconsistent with pipeline safety.

For the foregoing reasons, MTB has further amended §§ 192.313(a)(4) and 195.212(b)(3) by adding to each section a new subdivision (B) to allow the field bending of small diameter steel pipe with a longitudinal seam without placing the seam near the neutral axis irrespective of whether a bending mandrel is used. MTB is cognizant of the fact that this issue was not specifically addressed in

BEGIN LAST LINE OF TEXT
PAGE NUMBER
EPA Form 2350-4 (4-80)
TYPING GUIDE SHEET

the Notice but feels that it is within the broad scope and intent of the Notice, and therefore it is appropriate to include it in the final rules. However, in keeping with MTB's policy to ensure that the public has full opportunity to participate in the rulemaking process, MTB is delaying the effective date of § 192.313(a)(4)(B) and § 195.212(b)(3)(B) until November 3, 1977 to permit any interested person the opportunity to comment before the rule becomes effective. If no adverse comment is received that raises substantial doubt as to the desirability of the amendment, it will become effective November 3, 1977 as written.

REPORT OF THE TECHNICAL PIPELINE SAFETY STANDARDS COMMITTEE

Section 4(b) of the Natural Gas Pipeline Safety Act of 1968 requires that all proposed standards and amendments to such standards pertaining to gas pipelines be submitted to the Committee and that the Committee be afforded a reasonable opportunity to prepare a report on the technical feasibility, reasonableness, and practicability of each proposal. This amendment to Part 192 was submitted as Item A-2 in a list of two proposed amendments at a meeting in Washington, D.C., on December 16 and 17, 1976. On January 12, 1977, the Committee filed the following favorable report. A minority report was not filed.

This communication is the official report of the Technical Pipeline Safety Standards Committee concerning the Committee's action on two amendments to 49 CFR Part 192 proposed by the Office of Pipeline Safety Operations and other matters which the Committee decided should be brought to the attention of the Department of Transportation.

The following described actions were taken by the Committee at a meeting held in Washington, D.C. on December 16 and 17, 1976.

Item A-2 was a proposal by OPSO to revise § 192.313(a)(4), Bends and elbows. By an affirmative vote of 12-1 the Committee found that the following language for § 192.313(a)(4) is technically feasible, reasonable, and practicable.

* * * * *

[The language suggested is adopted in the final rule as discussed in the "Discussion of Comments Section" above.]

After additional discussions of agenda Item A-2, by an affirmative vote of 12-1, the Committee further recommended that § 192.313 be further modified to provide that for pipe with a D/t ratio less than 70, the location of the longitudinal seam may be at the discretion of the operator.

PRINCIPAL AUTHORS

Ralph T. Simmons, Regulations Specialist, and Robert L. Beauregard, Attorney, Office of the General Counsel.

In consideration of the foregoing, Parts 192 and 195 of Title 49 of the Code of Federal Regulations are amended as follows:

1. Section 192.313(a)(4) is amended to read as follows:

§ 192.313 Bends and elbows.

(a) * * *

(4) On pipe containing a longitudinal weld, the longitudinal weld must be as near as practicable to the neutral axis of the bend unless—

(i) The bend is made with an internal bending mandrel; or

(ii) The pipe is 12 inches or less in outside diameter with a diameter to wall thickness ratio less than 70.

* * * * *

(Sec. 3, Pub. L. 90-481, 82 Stat. 721, 49 USC 1672; for offshore gathering lines, Sec. 105, Pub. L. 93-633, 88 Stat. 2157, 49 USC 1804; 40 FR 43901, 49 CFR 1.53.)

2. Section 195.212(b)(3) is amended to read as follows:

§ 195.212 Bending of pipe.

* * * * *

(b) * * *

(3) On pipe containing a longitudinal weld, the longitudinal weld must be as near as practicable to the neutral axis of the bend unless—

(i) The bend is made with an internal bending mandrel; or

(ii) The pipe is 12 inches or less in outside diameter with a diameter to wall thickness ratio less than 70.

* * * * *

(Sec. 6, Pub. L. 89-670, 80 Stat. 937, 49 U.S.C. 1655; 18 U.S.C. 831-835; 40 FR 43901, 49 CFR 1.53.)

JOHN J. FEARNSIDES,
Acting Director,
Materials Transportation Bureau.

[FR Doc.77-24303 Filed 8-24-77;8:45 am]

EPA Form 2350-4 (4-80)
TYPING GUIDE SHEET

DEPARTMENT OF TRANSPORTATION
MATERIALS TRANSPORTATION BUREAU
WASHINGTON, D.C. 20590

[Amdts. 192-29; 195-12; Docket No. OPSO-38]

PART 192—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE

PART 195—TRANSPORTATION OF LIQUIDS BY PIPELINE

Longitudinal Seams in Pipe Bends; Correction

AGENCY: Materials Transportation Bureau, DOT.

ACTION: Correction.

SUMMARY: This document corrects a final rules document that appeared at page 42865 in the FEDERAL REGISTER of Thursday, August 25, 1977 (FR Doc. 77-24303).

EFFECTIVE DATE: November 3, 1977.

FOR FURTHER INFORMATION CONTACT:

Peggy Hammond, 202-426-0135.

SUPPLEMENTARY INFORMATION: By Amendments 192-29 and 195-12, new §§ 192.313(a)(4)(ii) and 195.212(b)(3)(ii) were added, respectively, to Parts 192 and 195 to provide that the longitudinal seam of steel pipe need not be placed near the neutral axis during bending if—

> "The pipe is 12 inches or less in outside diameter with a diameter to wall thickness ratio less than 70."

As stated in the preamble, the rationale for adopting this provision was that "safe bends in steel pipe 12 inches or less in outside diameter with a D/t (diameter to thickness) ratio of less than 70 can be made without using an internal bending mandrel even though the longitudinal seam is not placed near the neutral axis of the bend." This rationale purportedly was based on comments received on Notice 76-2 (41 FR 46463, Oct. 21, 1976), which proposed to remove the requirement for placement of the longitudinal seam near the neutral axis when a bending mandrel is used. Recently, however, several interested persons have pointed out that both the final rule and the rationale incorrectly reflect the written comments in the docket and the position of the Technical Pipeline Safety Standards Committee (TPSSC). These persons have stated that the view of commenters and the TPSSC was that pipe 12 inches and under in diameter can be bent safely without a mandrel and without placing the longitudinal seam near the neutral axis, irrespective of the D/t ratio. In addition, they stated the record shows that any size pipe with a D/t ratio of less than 70 can likewise be bent safely.

After thoroughly reviewing the matter, it appears that Amendments 192-29 and 195-12 are in fact inconsistent with the record as the interested persons have stated.

Accordingly, the following corrections are made:

1. Section 192.313(a)(4)(ii) is corrected to read as follows:

§ 192.313 Bends and elbows.

(a) * * *

(4) * * *

(ii) The pipe is 12 inches or less in outside diameter or has a diameter to wall thickness ratio less than 70.

(Sec. 3, Pub. L. 90-481, 82 Stat. 721, 49 USC 1672; for offshore gathering lines, Sec. 105, Pub. L. 93-633, 88 Stat. 2157, 49 USC 1804; 49 CFR 1.53.)

* * * * *

2. Section 195.212(b)(3)(ii) is corrected to read as follows:

§ 195.212 Bending of pipe.

* * * * *

(b) * * *

(3) * * *

(ii) The pipe is 12 inches or less in outside diameter or has a diameter to wall thickness ratio less than 70.

* * * * *

(Sec. 6, Pub. L. 89-670, 80 Stat. 937, 49 USC 1655; 18 USC 831-835; 49 CFR 1.53.)

Issued in Washington, D.C., on November 18, 1977.

L. D. SANTMAN,
Acting Director,
Materials Transportation Bureau.

[FR Doc.77-33914 Filed 11-23-77;8:45 am]

DEPARTMENT OF TRANSPORTATION
RESEARCH AND SPECIAL PROGRAMS DIRECTORATE
WASHINGTON, D.C. 20590

Title 49—Transportation

CHAPTER I—MATERIALS TRANSPORTATION BUREAU, DEPARTMENT OF TRANSPORTATION

SUBCHAPTER D—PIPELINE SAFETY

[Amdts. 192-32, 195-14; Docket No. 77-10]

PART 192—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE

PART 195—TRANSPORTATION OF LIQUIDS BY PIPELINE

Qualification and Design of Steel Pipe

AGENCY: Materials Transportation Bureau.

ACTION: Final rule.

SUMMARY: This amendment updates the existing incorporation by reference of API Standard 5LS, "API Specification for Spiral-Weld Line Pipe," and API Standard 5LX, "API Specification for High-Test Line Pipe," to include in Part 192, the March 1976 Supplement and the 1977 edition of each document and in Part 195, the 1977 edition of each document..

DATE: This amendment becomes effective June 1, 1978.

FOR FURTHER INFORMATION CONTACT:

Frank E. Fulton, 202-426-2082.

SUPPLEMENTARY INFORMATION: This amendment makes Parts 192 and 195 conform with recent developments in the manufacture and design of steel pipe. These subjects are now regulated, in part, through an incorporation by reference of API Standard 5LS and API Standard 5LX. At present, the 1975 editions are the latest applicable editions of API 5LS and 5LX listed in Parts 192 and 195. This amendment updates the lists to include the 1977 editions in both parts and the March 1976 Supplements in Part 192.

Of particular importance is that by referencing the March 1976 Supplements and the 1977 editions of API 5LS and 5LX, pipeline operators will be permitted to use Grade X-70 pipe in the transportation of gas. Grade X-70 is more economical for certain uses than other available grades of steel pipe because of its high strength, which permits the use of thinner walled pipe. It is projected for use in the pipeline approved under the Alaska Natural Gas Transportation Act of 1976 (15 U.S.C. 719) to transport gas from the North Slope to the lower 48 States.

The Office of Pipeline Safety Operations proposed adoption of the later editions of API 5LS and 5LX in a Notice of Proposed Rulemaking (Notice 77-7) issued on December 7, 1977 (42 FR 62397, Dec. 12, 1977). Interested persons were invited to participate in the rulemaking proceeding by submitting written data, views, or arguments by January 12, 1978. In addition, in accordance with Sec. 4(b) of the Natural Gas Pipeline Safety Act of 1968 (49 U.S.C. 1673(b)), the Technical Pipeline Safety Standards Committee (TPSSC) considered the proposal at its meeting in Washington, D.C., on January 17 and 18, 1978. The TPSSC's report is set forth below.

Twelve persons submitted comments in response to Notice 77-7, 3 trade associations and 9 gas pipeline companies. All the commenters favored adoption of the later editions of API 5LX and 5LS.

One person suggested that Grade X-70 pipe be required to pass the Charpy impact testing set forth in Supplementary Test SR5 in the 1977 editions of 5LS and 5LX. The SR5 test, which is intended to substantiate material quality and to mitigate the potential for brittle or shear pipe fractures, is not obligatory under the provisions of 5LS and 5LX and was not discussed in Notice 77-7. The test, therefore, could not be made binding under Part 192 or Part 195 without issuing an additional Notice of Proposed Rulemaking on the subject. Since the commenter did not submit evidence that would justify imposing the Charpy test as a general rule and the other available information does not show that potential fractures are a general problem in Grade X-70 pipe, there does not appear to be

EPA Form 2300-4 (4-80)

TYPING GUIDE SHEET

an immediate need to pursue the matter further. It is recognized, however, that under certain conditions of high stress and low temperature, the potential for fractures may increase in thin walled pipe. Under these conditions, operators are already required by the general design requirements of Parts 192 and 195 to take additional precautions (see §§ 192.53 and 195.102). Further consideration will be given to this problem in a future rulemaking proceeding on pipelines operating in low temperature environments.

Several commenters suggested that the introductory language in Section II of Appendix A and Section I of Appendix B to Part 192 and in § 195.3(a) be amended to permit the use of components which provide a comparable level of safety but do not comply with any of the listed editions of the documents incorporated by reference. Since the safety standards were adopted, the use of items in stock or the reuse of salvagable items has been permitted only if the items meet the requirements of Part 192 or Part 195, as the case may be, and where applicable, the requirements of a listed edition of a referenced document. Although this requirement may be too inflexible in certain situations, it was not proposed to be changed in Notice 77-7 and thus cannot be changed in the final rules. However, the problem will be given further attention in the future when action is taken on a petition for rulemaking filed by the Interstate Natural Gas Association of America. This petition proposes that criteria be established for the use of materials that do not conform with any listed edition of a listed document.

REPORT OF THE TECHNICAL PIPELINE SAFETY STANDARDS COMMITTEE

Section 4(b) of the Natural Gas Pipeline Safety Act of 1968 requires that all proposed standards and amendments to such standards pertaining to gas pipelines be submitted to the Committee and that the Committee be afforded a reasonable opportunity to prepare a report on the technical feasibility, reasonableness, and practicability of each proposal. This amendment to Part 192 was submitted as Item A in a list of items before the Committee at a meeting in Washington, D.C., on January 17 and 18, 1978. On March 10, 1978, the Committee filed the following favorable report. A minority report was not filed.

This communication is the official report of the Technical Pipeline Safety Standards Committee concerning the Committee's action on one amendment to 49 CFR Part 192 proposed by the Office of Pipeline Safety Operations, on revisions of Subpart I of Part 192, as proposed by Committee members, and on other matters the Committee decided should be brought to the attention of the Department of Transportation.

The following described actions were taken by the Committee at a meeting held in Washington, D.C., on January 17 and 18, 1978.

A. PROPOSAL BY OPSO TO AMEND THE REQUIREMENTS IN RESPECT TO QUALIFICATION AND DESIGN OF STEEL PIPE

OPSO proposed to amend the requirements of Appendix A and Appendix B of Part 192 pertaining to qualification and design of steel pipe as published in Notice 77-7, Docket No. 77-10. By a unanimous affirmative vote of the nine members present, the Committee found the following language to be technically feasible, reasonable and practicable.

[The language suggested is adopted in the final rules.]

* * * * *

NOTE.—It has been determined that this document does not contain a major regulation requiring preparation of a Regulatory Analysis under DOT procedures or Executive Order 12044.

In consideration of the foregoing, Parts 192 and 195 of Title 49 of the Code of Federal Regulations are amended as set forth below.

1. Section II of Appendix A to Part 192 is amended to read as follows:

APPENDIX A—INCORPORATED BY REFERENCE

* * * * *

II. Documents incorporated by reference. Numbers in parentheses indicate applicable editions. Only the latest listed edition applies except that an earlier listed edition may be followed with respect to pipe or components which are manufactured, designed, or installed in accordance with the earlier edition before the latest edition is adopted, unless otherwise provided in this part.

A. * * *

(5) API Standard 5LS "API Specification for Spiral-Weld Line Pipe" (1967, 1970, 1971 plus Supp. 1, 1973 plus Supp. 1, 1975 plus Supp. 1, and 1977).

(6) API Standard 5LX "API Specification for High-Test Line Pipe" (1976, 1970, 1971 plus Supp. 1, 1973 plus Supp. 1, 1975 plus Supp. 1, and 1977).

* * * * *

2. Section I of Appendix B to Part 192 is amended to read as follows:

APPENDIX B—QUALIFICATION OF PIPE

I. Listed Pipe Specifications. Numbers in parentheses indicate applicable editions. Only the latest listed edition applies except that an earlier listed edition may be followed with respect to pipe or components which are manufactured, designed, or installed in accordance with the earlier edition before the latest edition is adopted, unless otherwise provided in this part.

* * * * *

API 5LS, Steel pipe (1967, 1970, 1971 plus Supp. 1, 1973 plus Supp. 1, 1975 plus Supp. 1, and 1977).

API 5LX, Steel pipe (1967, 1970, 1971 plus Supp. 1, 1973 plus Supp. 1, 1975 plus Supp. 1, and 1977).

* * * * *

(Sec. 3, Pub. L. 90-481, 82 Stat. 721, (49 U.S.C. 1672); for offshore gathering lines, sec. 105, Pub. L. 93-633, 88 Stat. 2157, (49 U.S.C. 1804); 49 CFR 1.53 and App. A to Part 1.)

3. In § 195.3, paragraphs (a) and (c)(1) (iv) and (v) are revised to read as follows:

§ 195.3 Matter incorporated by reference.

(a) There are incorporated by reference in this part all materials referred to in this part that are not set forth in full in this part. These materials are hereby made a part of this regulation. Applicable editions are listed in paragraph (c) of this section in parentheses following the title of the referenced material. Only the latest listed edition applies, except that an earlier listed edition may be followed with respect to components which are manufactured, designed, or installed in accordance with the earlier edition before the latest edition is adopted, unless otherwise provided in this part.

* * * * *

(c) * * *

(1) * * *

(iv) API Specification 5LS "API Specification for Spiral-Weld Line Pipe" (1969, 1975, and 1977).

(v) API Specification 5LX "API Specification for High-Test Line Pipe" (1969, 1975, and 1977).

* * * * *

(Secs. 6, Pub. L. 89-670, 80 Stat. 937, (49 U.S.C. 1655); (18 U.S.C. 831-835); 49 CFR 1.53 and App. A to Part 1.)

Issued in Washington, D.C., on April 25, 1978.

L. D. SANTMAN,
Acting Director,
Materials Transportation
Bureau.

EPA Form 2360-4 (4-80)
(PREVIOUSLY CIR. EPA FORM 327)

TYPING GUIDE SHEET

available for inspection in the Materials Transportation Bureau, Washington, D.C. In addition, materials incorporated by reference are available as follows:

(1) American Petroleum Institute (API), 1801 K Street, N.W., Washington, D.C. 20006, or 300 Corrigan Tower Building, Dallas, Texas 75201.

(2) The American Society of Mechanical Engineers (ASME), United Engineering Center, 345 East 47th Street, New York, N.Y. 10017.

(3) Manufacturers Standardization Society of the Valve and Fittings Industry (MSS), 1815 North Fort Myer Drive, Arlington, Va. 22209.

(4) American National Standards Institute (ANSI), 1430 Broadway, New York, N.Y. 10018. (Formerly the United States of America Standards Institute (USASI). All current standards issued by USASI and ASA have been redesignated as American National Standards and continue in effect.)

(5) American Society for Testing and Materials (ASTM), 1916 Race Street, Philadelphia, Pa. 19103.

(c) The full title for the publications incorporated by reference in this part are as follows:

(1) American Petroleum Institute:

(i) API Standard 6D "API Specification for Pipeline Valves," which may be obtained from the Dallas office (1968, 1974).

(ii) API Standard 1104 "Standard for Welding Pipe Lines and Related Facilities" (1968, 1973).

(iii) API Specification 5L "API Specification for Line Pipe" (1969, 1975).

(iv) API Specification 5LS "API Specification for Spiral-Weld Line Pipe" (1969, 1975).

(v) API Specification 5LX "API Specification for High-Test Line Pipe" (1969, 1975).

(2) ASME Code is the American Society of Mechanical Engineers Boiler and Pressure Vessel Code, Section VIII, "Pressure Vessels, Division 1" (1968, 1974).

(3) Manufacturers Standardization Society of the Valve and Fitting Industry:

(i) MSS Standard practice SP-48 "Steel Butt-Welding Fittings (26 inch and larger)" (1969).

(ii) MSS Standard Practice SP-63 "High Strength Wrought Welding Fitting" (1969).

"Specification for High-Test Wrought Welding Fittings" (1973).

(4) American National Standards Institute:

(i) ANSI B16.9 "Factory Made Wrought Steel Butt-Welding Fittings" (1964, 1971).

(ii) ANSI B31.4 "Liquid Petroleum Transportation Piping Systems" (1966, 1974).

(5) American Society for Testing and Materials:

(i) ASTM Specification A53 "Standard Specification for Welded and Seamless Steel Pipe" (1968, 1973).

(ii) ASTM Specification A106 "Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service" (1968, 1972a).

(iii) ASTM Specification A134 "Standard Specification for Electric-Fusion (Arc)-Welded Steel Plate Pipe, Sizes 16 in. and Over" (1968, 1973).

(iv) ASTM Specification A135 "Standard Specification for Electric-Resistance-Welded Steel Pipe" (1968, 1973a).

(v) ASTM Specification A139 "Standard Specification for Electric-Fusion (Arc)-Welded Steel Pipe, (Sizes 4 in. and Over)" (1968, 1973).

(vi) ASTM Specification A155 "Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service" (1968, 1972a).

(vii) ASTM Specification A211 "Standard Specification for Spiral-Welded Steel or Iron Pipe" (1968, 1973).

(viii) ASTM Specification A333 "Standard Specification for Seamless and Welded Steel Pipe for Low-Temperature Service" (1968, 1973).

(ix) ASTM Specification A381 "Standard Specification for Metal-Arc-Welded Steel Pipe for High-Pressure Transmission Systems" (1969, 1973).

(40 FR 43901, 49 CFR 1.53) [34 FR 15473, Oct. 4, 1969, as amended by Amdt. 195-2, 35 FR 17184, Nov. 7, 1970; Amdt. 195-9, 41 FR 13592, Mar. 31, 1976]

§ 195.4 Acceptable petroleum commodities.

No carrier may transport any petroleum or petroleum product unless the petroleum or petroleum product is chemically compatible with both the pipeline, including all components, and any other commodity that it may come into contact with while in the pipeline.

EPA Form 2350-4 (4-80)
(PREVIOUSLY CIN. EPA FORM 241)
TYPING GUIDE SHEET

pipeline in interstate and foreign commerce of hazardous materials that are subject to Parts 172 and 173 of this chapter, petroleum, and petroleum products.

(b) This part does not apply to—

(1) Transportation of water or any commodity that is transported in a gaseous state;

(2) Transportation through a pipeline by gravity;

(3) Transportation through pipelines that operate at a stress level of 20 percent or less of the specified minimum yield strength of the line pipe in the system;

(4) Except for Subpart B of this part, transportation of petroleum in onshore pipelines in rural areas between a production facility and a carrier's trunkline reception point, and

(5) Transportation in offshore pipelines which are located upstream from the outlet flange of each facility on the Outer Continental Shelf where hydrocarbons are produced or where produced hydrocarbons are first separated, dehydrated, or otherwise processed, whichever facility is farther downstream.

(40 FR 43901, 49 CFR 1.53) [34 FR 15473, Oct. 4, 1969, as amended by Amdt. 195–11, 41 FR 34040, Aug. 12, 1976]

§ 195.2 Definitions.

As used in this part—

"Barrel" means a unit of measurement equal to 42 U.S. standard gallons.

"Carrier" means a pipeline carrier subject to sections 831–835 of title 18, United States Code.

"Commodity" means a hazardous material that is subject to Parts 172 and 173 of this chapter, petroleum, and petroleum products.

"Component" means any part of a pipeline which may be subjected to pump pressure including, but not limited to, pipe, valves, elbows, tees, flanges, and closures.

"Line section" means a continuous run of pipe between adjacent pressure pump stations, between a pressure pump station and terminal or working tankage, between a pressure pump station and a block valve, or between adjacent block valves.

"Nominal wall thickness" means the wall thickness listed in the pipe specifications.

"Offshore" means beyond the line of ordinary low water along that portion of the coast of the United States that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters.

"Pipe" or "line pipe" means a tube, usually cylindrical, through which a commodity flows from one point to another.

"Pipeline system" or "pipeline" means all parts of a carrier's physical facilities through which commodities move in transportation that is subject to this part, including, but not limited to, line pipe, valves and other appurtenances connected to line pipe, pumping units, fabricated assemblies associated with pumping units, metering and delivery stations and fabricated assemblies therein, and carrier-controlled breakout tankage.

"Secretary" means the Secretary of Transportation or any person to whom he has delegated authority in the matter concerned.

"Specified minimum yield strength" means the minimum yield strength, expressed in pounds per square inch, prescribed by the specification under which the material is purchased from the manufacturer.

"Stress level" means the level of tangential or hoop stress, usually expressed as a percentage of specified minimum yield strength.

"Surge pressure" means pressure produced by a change in velocity of the moving stream that results from shutting down a pump station or pumping unit, closure of a valve, or any other blockage of the moving stream.

[34 FR 15473, Oct. 4, 1969, as amended by Amdt. 195–5, 38 FR 2977, Jan. 31, 1973]

§ 195.3 Matter incorporated by reference.[1]

(a) There are incorporated by reference in this part all materials referred to in this part that are not set forth in full in this part. These materials are hereby made a part of this regulation. Applicable editions are listed in paragraph (c) of this section in parentheses following the title of the referenced material. Only the latest listed edition applies, except that an earlier listed edition may be followed with respect to components which were manufactured, designed, or installed before July 1, 1976, unless otherwise provided in this part.

---

[1] NOTE: Incorporation by reference provisions approved by the Director of the Federal Register, March 26, 1976.

EPA Form 2350-4 (4-80)
(PREVIOUSLY CIN, EPA FORM 297)
TYPING GUIDE SHEET

(b) All incorporated materials are available for inspection in the Materials Transportation Bureau, Washington, D.C. In addition, materials incorporated by reference are available as follows:

(1) American Petroleum Institute (API), 1801 K Street, N.W., Washington, D.C. 20006, or 300 Corrigan Tower Building, Dallas, Texas 75201.

(2) The American Society of Mechanical Engineers (ASME), United Engineering Center, 345 East 47th Street, New York, N.Y. 10017.

(3) Manufacturers Standardization Society of the Valve and Fittings Industry (MSS), 1815 North Fort Myer Drive, Arlington, Va. 22209.

(4) American National Standards Institute (ANSI), 1430 Broadway, New York, N.Y. 10018. (Formerly the United States of America Standards Institute (USASI). All current standards issued by USASI and ASA have been redesignated as American National Standards and continue in effect.)

(5) American Society for Testing and Materials (ASTM), 1916 Race Street, Philadelphia, Pa. 19103.

(c) The full title for the publications incorporated by reference in this part are as follows:

(1) American Petroleum Institute:

(i) API Standard 6D "API Specification for Pipeline Valves," which may be obtained from the Dallas office (1968, 1974).

(ii) API Standard 1104 "Standard for Welding Pipe Lines and Related Facilities" (1968, 1973).

(iii) API Specification 5L "API Specification for Line Pipe" (1969, 1975).

(iv) API Specification 5LS "API Specification for Spiral-Weld Line Pipe" (1969, 1975).

(v) API Specification 5LX "API Specification for High-Test Line Pipe" (1969, 1975).

(2) ASME Code is the American Society of Mechanical Engineers Boiler and Pressure Vessel Code, Section VIII, "Pressure Vessels, Division 1" (1968, 1974).

(3) Manufacturers Standardization Society of the Valve and Fitting Industry:

(i) MSS Standard practice SP-48 "Steel Butt-Welding Fittings (26 inch and larger)" (1969).

(ii) MSS Standard Practice SP-63 "High Strength Wrought Welding Fitting" (1969).

(iii) MSS Standard Practice SP-75 "Specification for High-Test Wrought Welding Fittings" (1973).

(4) American National Standards Institute:

(i) ANSI B16.9 "Factory Made Wrought Steel Butt-Welding Fittings" (1964, 1971).

(ii) ANSI B31.4 "Liquid Petroleum Transportation Piping Systems" (1966, 1974).

(5) American Society for Testing and Materials:

(i) ASTM Specification A53 "Standard Specification for Welded and Seamless Steel Pipe" (1968, 1973).

(ii) ASTM Specification A106 "Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service" (1968, 1972a).

(iii) ASTM Specification A134 "Standard Specification for Electric-Fusion (Arc)-Welded Steel Plate Pipe, Sizes 16 in. and Over" (1968, 1973).

(iv) ASTM Specification A135 "Standard Specification for Electric-Resistance-Welded Steel Pipe" (1968, 1973a).

(v) ASTM Specification A139 "Standard Specification for Electric-Fusion (Arc)-Welded Steel Pipe, (Sizes 4 in. and Over)" (1968, 1973).

(vi) ASTM Specification A155 "Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service" (1968, 1972a).

(vii) ASTM Specification A211 "Standard Specification for Spiral-Welded Steel or Iron Pipe" (1968, 1973).

(viii) ASTM Specification A333 "Standard Specification for Seamless and Welded Steel Pipe for Low-Temperature Service" (1968, 1973).

(ix) ASTM Specification A381 "Standard Specification for Metal-Arc-Welded Steel Pipe for High-Pressure Transmission Systems" (1969, 1973).

(40 FR 43901, 49 CFR 1.53) [34 FR 15473, Oct. 4, 1969, as amended by Amdt. 195-2, 35 FR 17184, Nov. 7, 1970; Amdt. 195-9, 41 FR 13592, Mar. 31, 1976]

§ 195.4 Acceptable petroleum commodities.

No carrier may transport any petroleum or petroleum product unless the petroleum or petroleum product is chemically compatible with both the pipeline, including all components, and any other commodity that it may come into contact with while in the pipeline.

EPA Form 2360-6 (4-80)
(PREVIOUSLY CIN. EPA FORM 231)
TYPING GUIDE SHEET

(13) *Part G, Item 1.* State the commonly used name of the commodity, such as fuel oil, regular gasoline, liquefied petroleum gas. If the commodity name is one not commonly used, state the name here and give a brief description of it under "Account of Accident by Responsible Official of Carrier."

(14) *Part G, Item 3.* State the year facility was installed or the best estimate possible. Pipe is excluded as the year of installation is required in Item 4 of Part H.

(15) *Part H.* Mark appropriate boxes and state information required in all items of this part only if the accident occurred in line pipe. If the accident occurred in any other part of the pipeline system, omit this part.

(16) *Part I.* Mark appropriate boxes and state information required in all items of this part if the accident was caused by corrosion in any component of the pipline system. In Item 4, state the length of time between the type of tests, such as pipe-to-soil potential, stated in Item 5.

(17) *Part J.* Complete all three items only if the accident was caused by equipment rupturing the pipeline. In Item 2, all the information stated on the closest line marker must be shown.

(b) In addition to the requirements of paragraph (a) of this section, in the space provided after Part J, the carrier shall enter an account of the accident containing the most reliable information to which the carrier has access at the time of reporting, sufficiently detailed and complete to convey an understanding of the accident. This account may be continued on an extra sheet of paper if more space is needed.

(c) At the bottom of the back of DOT Form 7000-1, the carrier shall state the name and title of the pipeline official responsible for compiling and filing the report along with the telephone number at which this official can be reached, and the date the report was completed.

§ 195.58 Changes in or additions to accident report.

Whenever a carrier receives any changes in the information reported or additions to the original report on DOT Form 7000-1 it shall immediately file a supplemental report with the Director, Office of Pipeline Safety, Department of Transportation, Washington, D.C. 20590.

[34 FR 15473, Oct. 4, 1969, as amended by Amdt. 195-5, 38 FR 2978, Jan. 31, 1973]

§ 195.60 Carrier assistance in investigation.

If the Department of Transportation investigates an accident, the carrier involved shall make available to the representative of the Department all records and information that in any way pertain to the accident, and shall afford all reasonable assistance in the investigation of the accident.

§ 195.62 Supplies of accident report DOT Form 7000-1.

Each carrier shall maintain an adequate supply of forms that are a facsimile of DOT Form 7000-1 to enable it to promptly report accidents. The Department will, upon request, furnish specimen copies of the form. Requests should be addressed to the Director, Office of Pipeline Safety, Department of Transportation, Washington, D.C. 20590.

[34 FR 15473, Oct. 4, 1969, as amended by Amdt. 195-5, 38 FR 2978, Jan. 31, 1973]

Subpart C—Design Requirements

§ 195.100 Scope.

This subpart prescribes minimum design requirements for new pipeline systems constructed with steel pipe and for relocating, replacing, or otherwise changing existing systems constructed with steel pipe. However, it does not apply to the movement of line pipe covered by § 195.424.

§ 195.102 Design temperature.

Material for components of the system must be chosen for the temperature environment in which the components will be used so that the pipeline will maintain its structural integrity.

§ 195.104 Variations in pressure.

If, within a pipeline system, two or more components are to be connected at a place where one will operate at a higher pressure than another, the system must be designed so that any component operating at the lower pressure will not be overstressed.

§ 195.106 Internal design pressure.

(a) Internal design pressure for the pipe in a pipeline is determined in accordance with the following formula:

$$P=\frac{2St}{D}\times E\times F$$

P = Internal design pressure in pounds per square inch gauge.

BEGIN FIRST LINE OF TEXT HERE
CENTER OF PAGE
TOP OF IMAGE AREA
DROPPED HEAD: BEGIN SECTIONS HERE
BEGIN LAST LINE OF TEXT
BOTTOM OF IMAGE AREA OUTSIDE DIMENSION FOR TABLES AND ILLUSTRATIONS
3/8"
PAGE NUMBER
EPA Form 2350-4 (4-80)
(PREVIOUSLY CIN. EPA FORM 247)
TYPING GUIDE SHEET

§ 195.6 Transportation of certain commodities.

(a) Except for petroleum, petroleum products, natural gasoline, and liquefied petroleum gases, no carrier may transport any commodity unless the carrier notifies the Secretary in writing, with the information listed in paragraph (b) of this section, at least 90 days before the date the transportation is to begin. If the Secretary determines that the transportaion of the commodity in the manner proposed would be unduly hazardous, he will, within 90 days after receipt of the notice, order the carrier, in writing, not to transport the commodity in the proposed manner until further notice. As soon as practicable after issuance of such an order, the Secretary will initiate appropriate action to determine whether and in what manner the commodity may be transported without undue hazard.

(b) The notice submitted to the Administrator by the carrier must state the chemical name, common name, hazard classification determined in accordance with Part 173 of this chapter, properties, and characteristics of the commodity to be transported. It must also include design specifications, including materials used in construction of the pipeline and the maximum operating pressures for the pipeline through which the commodity is to be transported.

[34 FR 15473, Oct. 4, 1969, as amended by Amdt. 195–1, 35 FR 5332, Mar. 31, 1970; Amdt. 195–5, 38 FR 2978, Jan. 31, 1973]

§ 195.8 Transportation of commodities in pipelines constructed with other than steel pipe.

No carrier may transport any commodity through a pipe that is constructed after October 1, 1970, of material other than steel unless the carrier has notified the Secretary in writing at least 90 days before the transportation is to begin. The notice must state the chemical name, common name, hazard classification (if any) determined in accordance with Part 173 of this chapter, properties, and characteristics of the commodity to be transported and the material used in construction of the pipeline. If the Secretary determines that the transportation of the commodity in the manner proposed would be unduly hazardous, he will, within 90 days after receipt of the notice order the carrier, in writing, not to transport the commodity in the proposed manner until further notice.

[Amdt. 195–1, 35 F.R. 5333, Mar. 31, 1970, as amended by Amdt. 195–2, 35 F.R. 17184, Nov. 7, 1970; Amdt. 195–5, 38 FR 2978, Jan. 31, 1973]

§ 195.10 Responsibility of carrier for compliance with this Part.

A carrier may make arrangements with another person for the performance of any action required by this part. However, the carrier is not thereby relieved from the responsibility for compliance with any requirement of this part.

Subpart B—Accident Reporting

§ 195.50 Scope.

This subpart prescribes rules governing the reporting of any failure in a pipeline system subject to this part in which there is a release of the commodity transported resulting in any of the following:

(a) Explosion or fire not intentionally set by the carrier.

(b) Loss of 50 or more barrels of liquid.

(c) Escape to the atmosphere of more than five barrels a day of liquefied petroleum gas or other liquefied gas.

(d) Death of any person.

(e) Bodily harm to any person resulting in one or more of the following:

(1) Loss of consciousness.

(2) Necessity to carry the person from the scene.

(3) Necessity for medical treatment.

(4) Disability which prevents the discharge of normal duties or the pursuit of normal activities beyond the day of the accident.

(f) Property damage of at least $1,000 to other than the carrier's facilities, based upon actual cost or reliable estimates.

§ 195.52 Telephonic notice of certain accidents.

(a) At the earliest practicable moment following discovery of a release of the commodity transported resulting in an event described in § 195.50, each carrier shall give notice, in accordance with paragraph (b) of this section, of any failure that—

(1) Caused a death or a personal injury requiring hospitalization;

(2) Resulted in either a fire or explosion not intentionally set by the carrier;

(3) Caused estimated damage to the property of the carrier or others, or both, of a total of $5,000 or more;

EPA Form 2350-4 (4-80)

TYPING GUIDE SHEET

(4) Resulted in pollution of any stream, river, lake, reservoir, or other similar body of water that violated applicable water quality standards, caused a discoloration of the surface of the water or adjoining shoreline, or deposited a sludge or emulsion beneath the surface of the water or upon adjoining shorelines; or

(5) In the judgment of the carrier, was significant even though it did not meet the criteria of any other subparagraph of this paragraph.

(b) Reports made under paragraph (a) of this section are made by telephone to area code 202, 426-0700 and must include the following information:

(1) Name and address of the carrier.

(2) Name and telephone number of the reporter.

(3) The location of the failure.

(4) The time of the failure.

(5) The fatalities and personal injuries, if any.

(6) All other significant facts known by the carrier that are relevant to the cause of the failure or extent of the damages.

[38 FR 7121, Mar. 16, 1973]

§ 195.54 Accident reporting.

Each carrier that experiences an accident that is required to be reported under this subpart shall, as soon as practicable but not later than 15 days after discovery of the accident, prepare and file an accident report, on DOT Form 7000-1 or a facsimile, with the Director, Office of Pipeline Safety, Department of Transportation, Washington, D.C. 20590. The carrier shall file two copies of each report and shall retain one copy at its principal place of business.

[34 FR 15473, Oct. 4, 1969, as amended by Amdt. 195-5, 38 FR 2978, Jan. 31, 1973]

§ 195.56 Instructions for preparing DOT Form 7000-1.

(a) Each carrier shall prepare each report of an accident on DOT Form 7000-1 or a facsimile, in accordance with the following instructions:

(1) *General.* Each applicable item must be marked or filled in as fully and as accurately as information accessible to the carrier at the time of filing the report will permit.

(2) *Part A.* Enter name as it is filed with the Interstate Commerce Commission. If the carrier's name is not filed with the Commission, enter the complete corporate name of the carrier. Enter the address of the carrier's principal place of business including zip code.

(3) *Part B, Item 1.* Enter the date the accident occurred or was discovered. If the accident was not discovered on the date it occurred, state this fact on the back of the form.

(4) *Part B, Item 2.* Enter the exact time in hours and minutes (i.e., 10:15) if known or a time range (i.e., 10:11) if exact time is not known. If the accident was not discovered on the date it occurred, enter the time it was discovered and state this fact, on the back of the form as in Part B, Item 1.

(5) *Part B, Item 3.* Enter all three names, State, county, city, or town, in or near which accident occurred.

(6) *Part B, Item 4.* Mark the appropriate box. If "other" is marked, state clearly on form what part of the pipeline system.

(7) *Part B, Item 5.* If the accident occurred in an uninhabited area, such as woods, cultivated field, swamp, etc., so state clearly on the form under Item 5. If not, attach a sketch to the form showing the part of the pipeline system where the accident occurred, and the location of the accident as related to significant landmarks. Each item shown on the sketch must be clearly and distinctly marked to identify it. Approximate distances from accident location to all landmarks shown on the sketch must be indicated.

(8) *Part C.* Mark the appropriate box or boxes. If applicable, mark more than one box. If "other" is marked, state clearly on form the exact origin of the release of commodity.

(9) *Part D.* Mark the appropriate box. If "other" is marked, clearly state the cause of the accident.

(10) *Part E.* Indicate a number under each heading including "0" if none. Report deaths, even if previously reported in accordance with § 195.52.

(11) *Part F, Items 1 and 2.* Report only material in the pipeline system that was actually damaged such as pipe, valves, or fittings. Do not include cost of commodity which was lost due to the accident or fittings used during repair which became permanently attached to the system. The dollar value of damage should be based on replacement at present day costs.

(12) *Part F, Items 3 and 4.* This is damage to property other than that of the carrier. Dollar value must be actual or the best estimate available.

EPA Form 2350-8 (4-80)
TYPING GUIDE SHEET

S=Yield strength in pounds per square inch determined in accordance with paragraph (b) of this section.

t=Nominal wall thickness of the pipe in inches. If this is unknown, it is determined in accordance with paragraph (c) of this section.

D=Nominal outside diameter of the pipe in inches.

E=Seam joint factor determined in accordance with paragraph (e) of this section.

F=A design factor of 0.72, except that a design factor of 0.60 is used for pipe, including risers, on a platform located offshore or on a platform in inland navigable waters, and 0.54 is used for pipe that has been cold worked to meet the specified minimum yield strength and is subsequently heated, other than by welding to 600° F. or more.

(b) The yield strength to be used in determining internal design pressure under paragraph (a) of this section is the specified minimum yield strength. If the specified minimum yield strength is not known, the yield strength is determined by performing all of the tensile tests of either API Standard 5L, 5LS, or 5LX on randomly selected test specimens with the following number of tests:

Pipe size	*Number of tests*
Less than 6 inches in outside diameter.	One test for each 200 lengths.
6 inches through 12¾ inches in outside diameter.	One test for each 100 lengths.
Larger than 12¾ inches in outside diameter.	One test for each 50 lengths.

If the average yield-tensile ratio exceeds 0.85, the yield strength of the pipe is taken as 24,000 p.s.i. If the average yield-tensile ratio is 0.85 or less, the yield strength of the pipe is taken as the lower of the following:

(1) Eighty percent of the average yield strength determined by the tensile tests.

(2) The lowest yield strength determined by the tensile tests.

(c) If the nominal wall thickness to be used in determining internal design pressure under paragraph (a) of this section is not known, it is determined by measuring the thickness of each piece of pipe at quarter points on one end. However, if the pipe is of uniform grade, size, and thickness, only 10 individual lengths or 5 percent of all lengths, whichever is greater, need be measured. The thickness of the lengths that are not measured

(2) Class designation or the maximum working pressure to which the valve may be subjected.

(3) Body material designation (the end connection material, if more than one type is used).

(4) Nominal valve size.

(40 FR 43901, 49 CFR 1.53) [34 FR 15473, Oct. 4, 1969, as amended by Amdt. 195-2, 35 FR 17185, Nov. 7, 1970; Amdt. 195-9, 41 FR 13592, Mar. 31, 1976]

§ 195.118 Fittings.

(a) Butt-welding type fittings must meet the marking end preparation and the bursting strength requirements of ANSI B16.9 or MSS Standard Practice SP-75, except that fittings manufactured, designed, or installed before July 1, 1976, may meet the requirements of MSS Standard Practice SP-48 or MSS Standard Practice SP-63.

(b) There may not be any buckles, dents, cracks, gouges, or other defects in the fitting that might reduce the strength of the fitting.

(c) The fitting must be suitable for the intended service and be at least as strong as the pipe and other fittings in the pipeline system to which it is attached.

(40 FR 43901, 49 CFR 1.53) [34 FR 15473, Oct. 4, 1969, as amended by Amdt. 195-9, 41 FR 13592, Mar. 31, 1976]

§ 195.120 Changes in direction: Provision for internal passage.

Each component of a main line system, other than station and terminal manifolds, that change direction within the pipeline system must have a radius of turn that readily allows the passage of pipeline scrapers, spheres, and internal inspection equipment

§ 195.122 Fabricated branch connections.

Each pipeline system must be designed so that the addition of any fabricated branch connections will not reduce the strength of the pipeline system.

§ 195.124 Closures.

Each closure to be installed in a pipeline system must comply with the ASME Boiler and Pressure Vessel Code, Section VIII, Pressure Vessels, Division 1, and must have pressure and temperature ratings at least equal to those of the pipe to which the closure is attached.

(40 FR 43901, 49 CFR 1.53) [Amdt. 195-9,

13592, Mar. 31, 1976]

TYPING GUIDE SHEET

41 FR 34040, Aug. 12, 1976, effective Aug. 1, 1977. For the convenience of the user, the superseded text is set out below:

(a) * * *

F=A design factor of 0.72, except that a design factor of 0.54 is used for pipe that has been cold worked to meet the specified minimum yield strength and is subsequently heated, other than by welding, to 600° F. or more.

§ 195.108 External pressure.

Any external pressure that will be exerted on the pipe must be provided for in designing a pipeline system.

§ 195.110 External loads.

(a) Anticipated external loads (e.g.), earthquakes, vibration, thermal expansion, and contraction must be provided for in designing a pipeline system. In providing for expansion and flexibility, section 419 of ANSI B31.4 must be followed.

(b) The pipe and other components must be supported in such a way that the support does not cause excess localized stresses. In designing attachments to pipe, the added stress to the wall of the pipe must be computed and compensated for.

(40 FR 43901, 49 CFR 1.53) [34 FR 15473, Oct. 4, 1969, as amended by Amdt. 195-9, 41 FR 13592, Mar. 31, 1976]

§ 195.112 New pipe.

Any new pipe installed in a pipeline system must comply with the following:

(a) The pipe must be made of steel of the carbon, low alloy-high strength, or alloy type that is able to withstand the internal pressures and external loads and pressures anticipated for the pipeline system

(b) The pipe must be made in accordance with a written pipe specification that sets forth the chemical requirements for the pipe steel and mechanical tests for the pipe to provide pipe suitable for the use intended.

(c) Each length of pipe with an outside diameter of 4 inches or more must be marked on the pipe or pipe coating with the specification to which it was made, the specified minimum yield strength or grade, and the pipe size. The marking must be applied in a manner that does not damage the pipe or pipe coating and must remain visible until the pipe is installed.

§ 195.114 Used pipe.

Any used pipe installed in a pipeline system must comply with § 195.112 (a) and (b) and the following:

(a) The pipe must be of a known specification and the seam joint factor must be determined in accordance with § 195.106(d). If the specified minimum yield strength or the wall thickness is not known, it is determined in accordance with § 195.106 (b) or (c) as appropriate.

(b) There may not be any—

(1) Buckles;

(2) Cracks, grooves, gouges, dents, or other surface defects that exceed the maximum depth of such a defect permitted by the specification to which the pipe was manufactured; or

(3) Corroded areas where the remaining wall thickness is less than the minimum thickness required by the tolerances in the specification to which the pipe was manufactured.

However, pipe that does not meet the requirements of subparagraph (3) of this paragraph may be used if the operating pressure is reduced to be commensurate with the remaining wall thickness.

[34 F.R. 15473, Oct. 4, 1969, as amended by Amdt. 195-2, 35 F.R. 17185, Nov. 7, 1970]

§ 195.116 Valves.

Each valve installed in a pipeline system must comply with the following:

(a) The valve must be of a sound engineering design.

(b) Materials subject to the internal pressure of the pipeline system, including welded and flanged ends, must be compatible with the pipe or fittings to which the valve is attached

(c) Each part of the valve that will be in contact with the commodity stream must be made of materials that are compatible with each commodity that it is anticipated will flow through the pipeline system.

(d) Each valve must be both hydrostatically shell tested and hydrostatically seat tested without leakage to at least the requirements set forth in section 5 of API Standard 6D.

(e) Each valve other than a check valve must be equipped with a means for clearly indicating the position of the valve (open, closed, etc.).

(f) Each valve must be marked on the body or the nameplate, with at least the following:

(1) Manufacturer's name or trademark.

TYPING GUIDE SHEET

(2) Class designation or the maximum working pressure to which the valve may be subjected.

(3) Body material designation (the end connection material, if more than one type is used).

(4) Nominal valve size.

(40 FR 43901, 49 CFR 1.53) [34 FR 15473, Oct. 4, 1969, as amended by Amdt. 195-2, 35 FR 17185, Nov. 7, 1970; Amdt. 195-9, 41 FR 13592, Mar. 31, 1976]

§ 195.118 Fittings.

(a) Butt-welding type fittings must meet the marking end preparation and the bursting strength requirements of ANSI B16.9 or MSS Standard Practice SP-75, except that fittings manufactured, designed, or installed before July 1, 1976, may meet the requirements of MSS Standard Practice SP-48 or MSS Standard Practice SP-63.

(b) There may not be any buckles, dents, cracks, gouges, or other defects in the fitting that might reduce the strength of the fitting.

(c) The fitting must be suitable for the intended service and be at least as strong as the pipe and other fittings in the pipeline system to which it is attached.

(40 FR 43901, 49 CFR 1.53) [34 FR 15473, Oct. 4, 1969, as amended by Amdt. 195-9 41 FR 13592, Mar. 31, 1976]

§ 195.120 Changes in direction: Provision for internal passage.

Each component of a main line system, other than station and terminal manifolds, that change direction within the pipeline system must have a radius of turn that readily allows the passage of pipeline scrapers, spheres, and internal inspection equipment.

§ 195.122 Fabricated branch connections.

Each pipeline system must be designed so that the addition of any fabricated branch connections will not reduce the strength of the pipeline system.

§ 195.124 Closures.

Each closure to be installed in a pipeline system must comply with the ASME Boiler and Pressure Vessel Code, Section VIII, Pressure Vessels, Division 1, and must have pressure and temperature ratings at least equal to those of the pipe to which the closure is attached.

(40 FR 43901, 49 CFR 1.53) [Amdt. 195-9, 41 FR 13592, Mar. 31, 1976]

§ 195.126 Flange connection.

Each component of a flange connection must be compatible with each other component and the connection as a unit must be suitable for the service in which it is to be used.

§ 195.128 Station piping.

Any pipe to be installed in a station that is subject to system pressure must meet the applicable requirements of this subpart.

§ 195.130 Fabricated assemblies.

Each fabricated assembly to be installed in a pipeline system must meet the applicable requirements of this subpart.

§ 195.132 Above ground tanks.

Each above ground tank must be designed to withstand the internal pressure produced by the commodity to be stored therein and any anticipated external loads.

Subpart D—Construction

§ 195.200 Scope.

This subpart prescribes minimum requirements for constructing new pipeline systems with steel pipe, and for relocating, replacing, or otherwise changing existing pipeline systems that are constructed with steel pipe. However, this subpart does not apply to the movement of pipe covered by § 195.424.

§ 195.202 Compliance with specifications or standards.

Each pipeline system must be constructed in accordance with comprehensive written specifications or standards that are consistent with the requirements of this part.

§ 195.204 Inspection—general.

Inspection must be provided to ensure the installation of pipe or pipeline systems in accordance with the requirements of this subpart. No person may be used to perform inspections unless that person has been trained and is qualified in the phase of construction he is to inspect.

§ 195.206 Material inspection.

No pipe or other component may be installed in a pipeline system unless it has been visually inspected at the site of installation to ensure that it is not damaged in a manner that could impair its strength or reduce its serviceability.

BEGIN FIRST LINE OF TEXT HERE
CENTER OF PAGE
TOP OF IMAGE AREA
DROPPED HEAD. BEGIN SECTIONS HERE
BEGIN LAST LINE OF TEXT
PAGE NUMBER
EPA Form 2250-4 (6-80)
TYPING GUIDE SHEET

§ 195.208 Welding of supports and braces.

Supports or braces may not be welded directly to pipe that will be operated at a pressure of more than 100 p.s.i.g.

§ 195.210 Pipeline location.

(a) Pipeline right-of-way must be selected to avoid, as far as practicable, areas containing private dwellings, industrial buildings, and places of public assembly.

(b) No pipeline may be located within 50 feet of any private dwelling, or any industrial building or place of public assembly in which persons work, congregate, or assemble, unless it is provided with at least 12 inches of cover in addition to that prescribed in § 195.248.

§ 195.212 Bending of pipe.

(a) Pipe must not have a wrinkle bend.

(b) Each field bend must comply with the following:

(1) A bend must not impair the serviceability of the pipe.

(2) Each bend must have a smooth contour and be free from buckling, cracks, or any other mechanical damage.

(3) On pipe containing a longitudinal weld, the longitudinal weld must be as near as practicable to the neutral axis of the bend.

(c) Each circumferential weld which is located where the stress during bending causes a permanent deformation in the pipe must be nondestructively tested either before or after the bending process.

(40 FR 43901, 49 CFR 1.53) [Amdt. 195-10, 41 FR 26018, June 24, 1976]

§ 195.214 Welding: General.

(a) Welding must be performed in compliance with this section and §§ 195.218 through 195.234.

(b) Welding must be performed in accordance with established written welding procedures that have been tested to assure that they will produce sound, ductile welds that comply with requirements of this subpart. Detailed records of these tests must be kept by the carrier involved.

§ 195.216 Welding: miter joints.

A miter joint is not permitted (not including deflections up to 3 degrees that are caused by misalignment).

(40 FR 43901, 49 CFR 1.53) [Amdt. 195-10, 41 FR 26018, June 24, 1976]

§ 195.218 Welding: Seam offset.

Seams on adjacent pipe lengths must be offset.

§ 195.220 Welds: Filler metal.

Filler metal must be at least equal in strength to the highest specified minimum yield strength of the pieces being welded and must fuse the pieces together.

§ 195.222 Welders: Testing.

Each welder must be qualified in accordance with one of the following editions of Section 3 of API Standard 1104:

(a) The 1973 edition, except that a welder may be qualified by radiography under subsection 3.51 without regard for the standards in subsection 6.9 for depth of undercutting adjacent to the root bead unless that depth is visually determined by use of a depth measuring device on all undercutting along the entire circumference of the weld; or

(b) If a welder is qualified before March 20, 1975, the 1968 edition, except that a welder may not requalify under the 1968 edition.

[Amdt. 195-8, 40 FR 10182, Mar. 5, 1975, as amended by Amdt. 195-8A, 40 FR 27223, June 27, 1975]

§ 195.224 Welding: Weather.

Welding must be protected from weather conditions that would impair the quality of the completed weld.

§ 195.226 Welding: Arc burns.

(a) Each arc burn must be repaired.

(b) An arc burn may be repaired by completely removing the notch by grinding, if the grinding does not reduce the remaining wall thickness to less than the minimum thickness required by the tolerances in the specification to which the pipe is manufactured. If a notch is not repairable by grinding, a cylinder of the pipe containing the entire notch must be removed.

(c) A ground may not be welded to the pipe or fitting that is being welded.

§ 195.228 Welds and welding inspection: Standards of acceptability.

(a) Each weld and welding must be inspected to ensure compliance with the requirements of this subpart. Visual inspection must be supplemented by nondestructive testing.

(b) The acceptability of a weld is determined according to the standards in Section 6 of the 1973 edition of API Standard 1104. However, the standards in subsection 6.9 for depth of undercutting adjacent to the root bead apply only if—

(1) That depth is visually determined by use of a depth measuring device on all undercutting along the entire circumference of the weld; and

(2) Visual determination of internal undercutting is made in all pipe of the same diameter in a pipeline, except where impractical at tie-in welds.

[Amdt. 195-8A, 40 FR 27223, June 27, 1975]

§ 195.230 Welds: Repair of defects.

(a) Except as provided in paragraph (b) of this section, a weld that is found unacceptable under § 195.228 may not be repaired unless—

(1) There are no cracks in the weld;

(2) The segment of the weld to be repaired was not previously repaired; and

(3) The weld is inspected after repair to assure its acceptability.

(b) In the case of offshore pipelines, a weld on a pipeline being installed from a pipelay vessel may be repaired if the repair is made in accordance with established written welding procedures that have been tested under § 195.214 to assure that they will produce sound ductile welds.

(40 FR 43901, 49 CFR 1.53) [Amdt. 195-11 41 FR 34040, Aug. 12, 1976]

§ 195.232 Welds: Removal of defects.

Except for offshore pipelines being installed from a pipelay vessel, a cylinder of the pipe containing the weld must be removed and the ends rebeveled whenever—

(a) The weld contains one or more cracks;

(b) The weld is not acceptable under § 195.228 and is not repaired; or

(c) The weld was repaired and the repair did not meet the requirements of § 195.228.

(40 FR 43901, 49 CFR 1.53) [Amdt. 195-11, 41 FR 34040, Aug. 12, 1976]

§ 195.234 Welds: Nondestructive testing and retention of testing records.

(a) A weld may be nondestructively tested by any process that will clearly indicate any defects that may affect the integrity of the weld.

(b) Any nondestructive testing of welds must be performed—

(1) In accordance with a written set of procedures for nondestructive testing; and

(2) With personnel that have been trained in the established procedures and in the use of the equipment employed in the testing.

(c) Procedures for the proper interpretation of each weld inspection must be established to ensure the acceptability of the weld under § 195.228.

(d) During construction, at least 10 percent of the girth welds made by each welder during each welding day must be nondestructively tested over the entire circumference of the weld.

(e) In the following locations, 100 percent of the girth welds must be nondestructively tested:

(1) At any onshore location where a loss of commodity could reasonably be expected to pollute any stream, river, lake, reservoir, or other body of water, and any offshore area unless impracticable, in which case only 90 percent of each day's welds need be tested.

(2) Within railroad or public road rights-of-way.

(3) At overhead road crossings and within tunnels.

(4) At pipeline tie-ins.

(5) Within the limits of any incorporated subdivision of a State government.

(6) Within populated areas, including but not limited to, residential subdivisions, shopping centers, schools, designated commercial areas, industrial facilities, public institutions, and places of public assembly.

(f) When installing used pipe, 100 percent of the old girth welds must be nondestructively tested.

(g) A record of the nondestructive testing must be retained by the carrier who is involved, including (if radiography is used) the developed film with, so far as practicable, the location of the weld. This record must be retained for 3 years after the line is placed in operation.

(40 FR 43901, 49 CFR 1.53) [34 FR 15473, Oct. 4, 1969, as amended by Amdt. 195-1, 35 FR 5335, Mar. 31, 1970; Amdt. 195-11, 41 FR 34040, Aug. 12, 1976]

§ 195.236 External corrosion protection.

Each component in the pipeline system must be provided with protection against external corrosion.

§ 195.238 External coating.

(a) No pipeline system component may be buried or submerged unless that com-

TYPING GUIDE SHEET

ponent has an external protective coating that—

(1) Is designed to mitigate corrosion of the buried or submerged component;

(2) Has sufficient adhesion to the metal surface to prevent underfilm migration of moisture;

(3) Is sufficiently ductile to resist cracking;

(4) Has enough strength to resist damage due to handling and soil stress; and

(5) Supports any supplemental cathodic protection.

In addition, if an insulating-type coating is used it must have low moisture absorption and provide high electrical resistance.

(b) All pipe coating must be inspected just prior to lowering the pipe into the ditch or submerging the pipe, and any damage discovered must be repaired.

(40 FR 43901, 49 CFR 1.53) [34 FR 15473, Oct. 4, 1969, as amended by Amdt. 195-11, 41 FR 34040, Aug. 12, 1976]

§ 195.242 Cathodic protection system.

(a) A cathodic protection system must be installed for all buried or submerged facilities to mitigate corrosion that might result in structural failure. A test procedure must be developed to determine whether adequate cathodic protection has been achieved.

(b) A cathodic protection system must be installed not later than 1 year after completing the construction.

(40 FR 43901, 49 CFR 1.53) [34 FR 15473, Oct. 4, 1969, as amended by Amdt. 195-11, 41 FR 34040, Aug. 12, 1976]

§ 195.244 Test leads.

(a) Except for offshore pipelines, electrical test leads used for corrosion control or electrolysis testing must be installed at intervals frequent enough to obtain electrical measurements indicating the adequacy of the cathodic protection.

(b) Test leads must be installed as follows:

(1) Enough looping or slack must be provided to prevent test leads from being unduly stressed or broken during backfilling.

(2) Each lead must be attached to the pipe so as to prevent stress concentration on the pipe.

(3) Each lead installed in a conduit must be suitably insulated from the conduit.

§ 195.246 Installation of pipe in a ditch.

(a) All pipe installed in a ditch must be installed in a manner that minimizes the introduction of secondary stresses and the possibility of damage to the pipe.

(b) All offshore pipe in water at least 12 feet deep but not more than 200 feet deep, as measured from the mean low tide, must be installed so that the top of the pipe is below the natural bottom unless the pipeline is supported by stanchions, held in place by anchors or heavy concrete coating, or an equivalent level of protection is provided.

(40 FR 43901, 49 CFR 1.53) [34 FR 15473, Oct. 4, 1969, as amended by Amdt. 195-11, 41 FR 34040, Aug. 12, 1976]

EFFECTIVE DATE: In § 195.246, the existing text was designated as paragraph (a) and paragraph (b) was added by Amdt. 195-11 at 41 FR 34040, Aug. 12, 1976, effective Aug. 1, 1977.

§ 195.248 Cover over buried pipeline.

(a) Unless specifically exempted in this subpart, all pipe must be buried so that it is below the level of cultivation. Except as provided in paragraph (b) of this section, the pipe must be installed so that the cover between the top of the pipe and the ground level, road bed, river bottom, or sea bottom, as applicable, complies with the following table:

Location	Cover (inches)	
	For normal excavation	For rock excavation[1]
Industrial, commercial, and residential areas	36	30
Crossings of inland bodies of water with a width of at least 100 ft from high water mark to high water mark	48	18
Drainage ditches at public roads and railroads	36	36
Deepwater port safety zone	48	24
Other offshore areas under water less than 12 ft-deep as measured from the mean low tide	36	18
Any other area	30	18

[1] Rock excavation is any excavation that requires blasting or removal by equivalent means.

(b) Less cover than the minimum required by paragraph (a) of this section and § 195.210 may be used if—

(1) It is impracticable to comply with the minimum cover requirements; and

(2) Additional protection is provided that is equivalent to the minimum required cover.

(40 FR 43901, 49 CFR 1.53) [34 FR 15473, Oct. 4, 1969, as amended by Amdt. 195–11, 41 FR 34040, Aug. 12, 1976]

EFFECTIVE DATE NOTE: In § 195.248, paragraph (a) was revised by Amdt. 195–11 at 41 FR 34040, Aug. 12, 1976, effective Aug. 1, 1977. For the convenience of the user the superseded text is set out below.

(a) Unless specifically exempted in this subpart, all pipe must be buried so that it is below the level of cultivation. Except as provided in paragraph (b) of this section, the pipe must be installed so that the cover between the top of the pipe and the ground level, road bed, or river bottom, as applicable, complies with the following table:

Location	Cover (inches)	
	For normal excavation	For Rock excavation[1]
Industrial, commercial, and residential areas	36	30
Crossings of bodies of water with a width of at least 100 feet from high water mark to high water mark	48	18
Drainage ditches at public roads and railroads	36	36
Any other area	30	18

[1] Rock excavation is any excavation that requires blasting or removal by equivalent means.

§ 195.250 Clearance between pipe and underground structures.

Any pipe installed underground must have at least 12 inches of clearance between the outside of the pipe and the extremity of any other underground structure, except that for drainage tile the minimum clearance may be less than 12 inches but not less than 2 inches. However, where 12 inches of clearance is impracticable, the clearance may be reduced if adequate provisions are made for corrosion control.

§ 195.252 Backfilling.

Backfilling must be performed in a manner that protects any pipe coating and provides firm support for the pipe.

§ 195.254 Above ground components.

(a) Any component may be installed above ground in the following situations, if the other applicable requirements of this part are complied with:

(1) Overhead crossings of highways, railroads, or a body of water.

(2) Spans over ditches and gullies.

(3) Scraper traps or block valves.

(4) Areas under the direct control of the carrier.

(5) In any area inaccessible to the public.

(b) Each component covered by this section must be protected from the forces exerted by the anticipated loads.

§ 195.256 Crossing of railroads and highways.

The pipe at each railroad or highway crossing must be installed so as to adequately withstand the dynamic forces exerted by anticipated traffic loads.

§ 195.258 Valves: General.

(a) Each valve must be installed in a location that is accessible to authorized employees and that is protected from damage or tampering.

(b) Each submerged valve located offshore or in inland navigable waters must be marked, or located by conventional survey techniques, to facilitate quick location when operation of the valve is required.

(40 FR 43901, 49 CFR 1.53) [34 FR 15473, Oct. 4, 1969, as amended by Amdt. 195–11, 41 FR 34041, Aug. 12, 1976]

EFFECTIVE DATE NOTE: In § 195.258, the existing text was designated as paragraph (a) and paragraph (b) was added by Amdt. 195–11 at 41 FR 34041, Aug. 12, 1976, effective Aug. 1, 1977.

§ 195.260 Valves: Location.

A valve must be installed at each of the following locations:

(a) On the suction end and the discharge end of a pump station in a manner that permits isolation of the pump station equipment in the event of an emergency.

(b) On each line entering or leaving a tank farm in a manner that permits isolation of the tank farm from other facilities.

(c) On each mainline at locations along the pipeline system that will minimize damage or pollution from accidental liquid discharge, as appropriate for the terrain in open country, for offshore areas, or for populated areas.

(d) On each lateral takeoff from a trunk line in a manner that permits shutting off the lateral without interrupting the flow in the trunk line.

(e) On each side of a water crossing that is more than 100 feet wide from

TYPING GUIDE SHEET

high-water mark to high-water mark unless the Secretary finds in a particular case that valves are not justified.

(f) On each side of a reservoir holding water for human consumption.

(40 FR 43901, 49 CFR 1.53) [34 FR 15473, Oct. 4, 1969, as amended by Amdt. 195-5, 38 FR 2973, Jan. 31, 1973; Amdt. 195-11, 41 FR 34041, Aug. 12, 1976]

EFFECTIVE DATE NOTE: In § 195.260, paragraph (c) was revised by Amdt. 195-11 at 41 FR 34041, Aug. 12, 1976, effective Aug. 1, 1977. For the convenience of the user, the superseded text is set out below:

* * * * *

(c) On each main line at locations along the pipeline system that will minimize damage from accidental product discharge, as appropriate for the terrain in open country or for the location near cities or other populated areas.

§ 195.262 Pumping equipment.

(a) Adequate ventilation must be provided in pump station buildings to prevent the accumulation of hazardous vapors. Warning devices must be installed to warn of the presence of hazardous vapors in the pumping station building.

(b) The following must be provided in each pump station:

(1) Safety devices that prevent overpressuring of pumping equipment, including the auxiliary pumping equipment within the pumping station.

(2) A device for the emergency shutdown of each pumping station.

(3) If power is necessary to actuate the safety devices, an auxiliary power supply.

(c) Each safety device must be tested under conditions approximating actual operations and found to function properly before the pumping station may be used.

(d) Except for offshore pipelines pumping equipment may not be installed—

(1) On any property that will not be under the control of the carrier; or

(2) Less than 50 feet from the boundary of the station.

(e) Adequate fire protection must be installed at each pump station. If the fire protection system installed requires the use of pumps, motive power must be provided for those pumps that is separate from the power that operates the station.

§ 195.264 Above ground tanks.

(a) A means must be provided for containing liquids in the event of spillage or tank failure.

(b) Tankage areas must be adequately protected against unauthorized entry.

(c) Normal and emergency relief venting must be provided for each tank.

§ 195.266 Construction records.

A complete record that shows the following must be maintained by the carrier involved for the life of each facility:

(a) The total number of girth welds and the number nondestructively tested, including the number rejected and the disposition of each rejected weld.

(b) The amount, location, and cover of each size of pipe installed.

(c) The location of each crossing of another pipeline.

(d) The location of each buried utility crossing.

(e) The location of each overhead crossing.

(f) The location of each valve, weighted pipe, corrosion test station, or other item connected to the pipe.

Subpart E—Hydrostatic Testing

AUTHORITY: The provisions of this Subpart E issued under secs. 831–835, Title 18, United States Code; secs. 6 (e)(4), (f)(3)(A), Department of Transportation Act (49 U.S.C. 1655 (e)(4), (f)(3)(A)); § 1.4(d)(6), Regulations of the Office of the Secretary of Transportation.

SOURCE: The provisions of this Subpart E are contained in Amdt. 195-2, 35 F.R. 17185, Nov. 7, 1970, unless otherwise noted.

§ 195.300 Scope.

This subpart prescribes minimum requirements for hydrostatic testing of newly constructed steel pipeline systems and for hydrostatic testing of existing steel pipeline systems that are relocated, replaced, or otherwise changed. However, this subpart does not apply to the movement of pipe covered by § 195.424.

§ 195.302 General requirements.

(a) Each new pipeline system, each pipeline system in which pipe has been relocated or replaced, or that part of a pipeline system that has been relocated or replaced, must be hydrostatically tested in accordance with this subpart without leakage.

(b) The test pressure for each hydrostatic test conducted under this section

BEGIN FIRST LINE OF TEXT HERE
CENTER OF PAGE
TOP OF IMAGE AREA

must be maintained for at least 24 hours throughout the part of the system that is being tested.

§ 195.304 Testing of components.

(a) Each hydrostatic test under § 195.302 must test all pipe and attached fittings, including components, unless otherwise permitted by paragraph (b) of this section.

(b) A component that is the only item being replaced or added to the pipeline system need not be hydrostatically tested under paragraph (a) of this section if the manufacturer certifies that either—

(1) The component was hydrostatically tested at the factory; or

(2) The component was manufactured under a quality control system that ensures each component is at least equal in strength to a prototype that was hydrostatically tested at the factory.

§ 195.306 Test medium.

(a) Except as provided in paragraph (b) of this section, water must be used as the test medium.

(b) Except for offshore pipelines, liquid petroleum that does not vaporize rapidly may be used as the test medium if—

(1) The entire pipeline section under test is outside of cities and other populated areas;

(2) Each building within 300 feet of the test section is unoccupied while the test pressure is equal to or greater than a pressure which produces a hoop stress of 50 percent of specified minimum yield strength;

(3) The test section is kept under surveillance by regular patrols during the test; and

(4) Continuous communication is maintained along entire test section..

(Sec. 6, Pub. L. 89-670; 40 FR 43901, 49 CFR 1.53) [Amdt. 195-2, Nov. 7, 1970, as amended by Amdt. 195-11, 41 FR 43152, Sept. 30, 1976]

§ 195.308 Testing of tie-ins.

Pipe associated with tie-ins must be hydrostatically tested, either with the section to be tied in or separately.

§ 195.310 Records.

(a) A record must be made of each hydrostatic test and that record must be retained as long as the facility tested is in use.

(b) The record required by paragraph (a) of this section must include the recording gauge charts, dead weight tester data, and the reasons for any failure during a test. Where elevation differences in the section under test exceed 100 feet, a profile of the pipeline that shows the elevation and test sites over the entire length of the test section must be included. Each recording gauge chart must also contain—

(1) The carrier's name, the name of the person responsible for making the test, and the name of the test company used, if any;

(2) The date and time of the test;

(3) The minimum test pressure;

(4) The test medium;

(5) A description of the facility tested; and

(6) An explanation of any pressure discontinuities that appear on any chart.

Subpart F—Operation and Maintenance

§ 195.400 Scope.

This subpart prescribes minimum requirements for operating and maintaining pipeline systems constructed with steel pipe.

§ 195.402 General requirements.

(a) Each carrier shall establish and maintain current written procedures:

(1) To ensure the safe operation and maintenance of its pipeline system in accordance with this Part during normal operations.

(2) To be followed during abnormal operations and emergencies.

(b) No carrier may operate or maintain its pipeline systems at a level of safety lower than that required by this subpart and the procedures it is required to establish under paragraph (a) of this section.

(c) Whenever a carrier discovers any condition that could adversely affect the safe operation of its pipeline system it shall correct it within a reasonable time. However, if the condition is of such a nature that it presents an immediate hazard to persons or property, the carrier may not operate the affected part of the system until it has corrected the unsafe condition.

(d) No carrier may operate any part of a pipeline system upon which construction was begun after March 31, 1970, or in the case of offshore pipelines located between a production facility and a carrier's trunkline reception point, af-

TYPING GUIDE SHEET

ter July 31, 1977, unless it was designed and constructed as required by this part.

(40 FR 43901, 49 CFR 1.53) [34 FR 15473, Oct. 4, 1969, as amended by Amdt. 195-11, 41 FR 34041, Aug. 12, 1976]

§ 195.404 Maps and records.

(a) Each carrier shall maintain current maps and records of its pipeline systems that include at least the following information:

(1) Location and identification of all major facilities.

(2) All crossings of public roads, railroads, rivers, buried utilities, and foreign pipelines.

(3) The maximum operating pressure of each pipeline.

(4) The diameter, grade, type, and nominal wall thickness of all pipe.

(b) Each carrier shall maintain daily operating records that indicate the discharge pressures at each pump station and any unusual operations of a facility. The carrier shall retain these records for at least 3 years.

(c) Each carrier shall also maintain for the useful life of that part of the pipeline system to which they relate, records that include the following:

(1) The date, location, and description of each repair made to its pipeline systems.

(2) A record of each inspection and each test required by this subpart.

[34 F.R. 15473, Oct. 4, 1969, as amended by Amdt. 195-1, 35 F.R. 5333, Mar. 31, 1970; Amdt. 195-2, 35 F.R. 17186, Nov. 7, 1970]

§ 195.406 Maximum operating pressure.

(a) Except for surge pressures and other variations from normal operations, no carrier may operate a pipeline at a pressure that exceeds any of the following:

(1) The internal design pressure of the pipe determined in accordance with § 195.106.

(2) The design pressure of any other component of the pipeline.

(3) Eighty percent of the test pressure for any part of the pipeline which has been hydrostatically tested under Subpart E of this part.

(4) Eighty percent of the factory test pressure or of the prototype test pressure for any individually installed component which is excepted from testing under § 195.304.

(b) No carrier may permit the pressure in a pipeline during surges or other variations from normal operations to exceed 110 percent of the operating pressure limit established under paragraph (a) of this section. Each carrier must provide adequate controls and protective equipment to control the pressure within this limit.

[Amdt. 195-2, 35 F.R. 17186, Nov. 7, 1970]

§ 195.408 Communications.

Each carrier shall have a communication system that insures the transmission of information required for the safe operation of its pipeline systems.

§ 195.410 Line markers.

(a) Except as provided in paragraphs (b) and (c) of this section, each carrier shall place and maintain line markers over each buried line in accordance with the following:

(1) Markers must be located at each public road crossing, at each railroad crossing, and in sufficient number along the remainder of each buried line so that its location is accurately known.

(2) The marker must state at least the following: "Warning" followed by the words "Petroleum (or the name of the commodity transported) Pipeline" (in lettering at least 1 inch high with an approximate stroke of one-quarter inch on a background of sharply contrasting color), the name of the carrier and a telephone number (including area code) where the carrier can be reached at all times. Markers at navigable waterway crossings must also contain the words "Do Not Anchor or Dredge" with lettering not less than 12 inches high with an approximate stroke of 1¾ inches on a background of sharply contrasting color.

(b) Line markers are not required in heavily developed urban areas such as downtown business centers where—

(1) The placement of markers is impracticable and would not serve the purpose for which markers are intended; and

(2) The local government maintains current substructure records.

(c) Line markers that have been installed before April 1, 1970, may be used until April 1, 1975.

(d) Each carrier shall provide line marking at locations where the line is above ground in areas that are accessible to the public.

TYPING GUIDE SHEET

BEGIN FIRST LINE OF TEXT HERE
CENTER OF PAGE
TOP OF IMAGE AREA
DROPPED HEAD; BEGIN SECTIONS HERE

§ 195.412 Inspection of rights-of-way and crossings under navigable waters.

(a) Each carrier shall, at intervals not exceeding 2 weeks, inspect the surface conditions on or adjacent to each pipeline right-of-way.

(b) Except for offshore pipelines, each carrier shall, at intervals not exceeding 5 years, inspect each crossing under a navigable waterway to determine the condition of the crossing.

§ 195.414 Cathodic protection.

(a) After March 31, 1973, no carrier may operate a pipeline that has an external surface coating material, unless that pipeline is cathodically protected. This paragraph does not apply to tank farms and buried pumping station piping.

(b) Each carrier shall electrically inspect each bare pipeline before April 1, 1975, to determine any areas in which active corrosion is taking place. The carrier may not increase its established operating pressure on a section of bare pipeline until the section has been so electrically inspected. In any areas where active corrosion is found, the carrier shall provide cathodic protection. Section 195.416 (f) and (g) applies to all corroded pipe that is found.

(c) Each carrier shall electrically inspect all tank farms and buried pumping station piping before April 1, 1973, as to the need for cathodic protection, and cathodic protection shall be provided where necessary.

(d) Notwithstanding the deadlines for compliance in paragraphs (a), (b), and (c) of this section, this section does not apply to offshore pipelines located between a production facility and a carrier's trunkline reception point until August 1, 1977.

(40 FR 43901, 49 CFR 1.53) [34 FR 15473, Oct. 4, 1969, as amended by Amdt. 195-2, 35 FR 17186, Nov. 7, 1970; Amdt. 195-11, 41 FR 34041, Aug. 12, 1976]

EFFECTIVE DATE NOTE: In § 195.414, paragraph (d) was added by Amdt. 195-11 at 41 FR 34041, Aug. 12, 1976, effective Aug. 1, 1977.

§ 195.416 External corrosion control.

(a) Each carrier shall, at intervals not exceeding 12 months, conduct tests on each underground facility in its pipeline systems that is under cathodic protection to determine whether the protection is adequate.

(b) Each carrier shall maintain the test leads required for cathodic protection in such a condition that electrical measurements can be obtained to ensure adequate protection.

(c) Each carrier shall, at intervals not exceeding 2 months, inspect each of its cathodic protection rectifiers.

(d) Each carrier shall, at intervals not exceeding 5 years, electrically inspect the bare pipe in its pipeline system that is not cathodically protected and must study leak records for that pipe to determine if additional protection is needed.

(e) Whenever any buried pipe is exposed for any reason, the carrier shall examine the pipe for evidence of external corrosion. If the carrier finds that there is active corrosion, that the surface of the pipe is generally pitted, or that corrosion has caused a leak, it shall investigate further to determine the extent of the corrosion.

(f) Any pipe that is found to be generally corroded so that the remaining wall thickness is less than the minimum thickness required by the pipe specification tolerances must either be replaced with coated pipe that meets the requirements of this part or, if the area is small, must be repaired. However, the carrier need not replace generally corroded pipe if the operating pressure is reduced to be commensurate with the limits on operating pressure specified in this subpart, based on the actual remaining wall thickness.

(g) If isolated corrosion pitting is found, the carrier shall repair or replace the pipe unless—

(1) The diameter of the corrosion pits is less than the nominal wall thickness as measured at the surface of the pipe, of the pipe; and

(2) The remaining wall thickness at the bottom of the pits is at least 70 percent of the nominal wall thickness.

(h) Each carrier shall clean, coat with material suitable for the prevention of atmospheric corrosion, and, maintain this protection for, each component in its pipeline system that is exposed to the atmosphere.

§ 195.418 Internal corrosion control.

(a) No carrier may transport any commodity that would corrode the pipe or other components of its pipeline system, unless it has investigated the corro-

BEGIN LAST LINE OF TEXT

TYPING GUIDE SHEET

sive effect of the commodity on the system and has taken adequate steps to mitigate corrosion.

(b) If corrosion inhibitors are used to mitigate internal corrosion the carrier shall use inhibitors in sufficient quantity to protect the entire part of the system that the inhibitors are designed to protect and shall also use coupons or other monitoring equipment to determine their effectiveness.

(c) The carrier shall, at intervals not exceeding 6 months, examine coupons or other types of monitoring equipment to determine the effectiveness of the inhibitors or the extent of any corrosion.

(d) Whenever any pipe is removed from the pipeline for any reason, the carrier must inspect the internal surface for evidence of corrosion. If the pipe is generally corroded such that the remaining wall thickness is less than the minimum thickness required by the pipe specification tolerances, the carrier shall investigate adjacent pipe to determine the extent of the corrosion. The corroded pipe must be replaced with pipe that meets the requirements of this part or, based on the actual remaining wall thickness, the operating pressure must be reduced to be commensurate with the limits on operating pressure specified in this subpart.

[34 F.R. 15473, Oct. 4, 1969, as amended by Amdt. 195-1, 35 F.R. 5333, Mar. 31, 1970]

§ 195.420 Valve maintenance.

(a) Each carrier shall maintain each valve that is necessary for the safe operation of its pipeline systems in good working order at all times.

(b) Each carrier shall, at intervals not exceeding 6 months, inspect each main line valve to determine that it is functioning properly.

(c) Each carrier shall provide protection for each valve from unauthorized operation and from vandalism.

§ 195.422 Pipeline repairs.

(a) Each carrier shall, in repairing its pipeline systems, insure that the repairs are made in a safe manner and are made so as to prevent damage to persons or property.

(b) No carrier may use any pipe, valve, or fitting, for replacement in repairing pipeline facilities, unless it is designed and constructed as required by this part.

§ 195.424 Pipe movement.

(a) No carrier may move any line pipe, unless the pressure in the line section involved is reduced to not more than 50 percent of the maximum operating pressure.

(b) No carrier may move any pipeline containing liquefied gases where materials in the line section involved are joined by welding unless—

(1) Movement when the pipeline does not contain liquefied gases is impractical;

(2) The procedures of the carrier under § 195.402 contain precautions to protect the public against the hazard in moving pipelines containing liquefied gases, including the use of warnings, where necessary, to evacuate the area close to the pipeline; and

(3) The pressure in that line section is reduced to the lower of the following:

(i) Fifty percent or less of the maximum operating pressure; or

(ii) The lowest practical level that will maintain the commodity in a liquid state with continuous flow, but not less than 50 p.s.i.g. above the vapor pressure of the commodity.

(c) No carrier may move any pipeline containing liquefied gases where materials in the line section involved are not joined by welding unless—

(1) The carrier complies with paragraphs (b) (1) and (2) of this section; and

(2) That line section is isolated to prevent the flow of commodity.

[Amdt. 195-2, 35 FR 17185, Nov. 7, 1970, as amended by Amdt. 195-7, 39 FR 19781, June 4, 1974]

§ 195.426 Scraper and sphere facilities.

No carrier may use a launcher or receiver that is not equipped with a relief device capable of safely relieving pressure in the barrel before insertion or removal of scrapers or spheres. The carrier must use a suitable device to indicate that pressure has been relieved in the barrel or must provide a means to prevent insertion or removal of scrapers or spheres if pressure has not been relieved in the barrel.

§ 195.428 Overpressure safety devices.

(a) Except as provided in paragraph (b) of this section, each carrier shall,

BEGIN FIRST LINE OF TEXT HERE
CENTER OF PAGE
TOP OF IMAGE AREA
DROPPED HEAD: BEGIN SECTIONS HERE

at intervals not exceeding 12 months, or 6 months in the case of pipelines used to carry liquefied gases, inspect and test each pressure limiting device, relief valve, pressure regulator, or other item of pressure control equipment to determine that it is functioning properly, is in good mechanical condition, and is adequate from the standpoint of capacity and reliability of operation for the service in which it is used.

(b) In the case of relief valves on pressure storage vessels containing liquefied gas, each carrier shall test each valve at intervals not exceeding 5 years

[Amdt. 195-4, 37 F.R. 18733, Sept. 15, 1972]

§ 195.430 Firefighting equipment.

Each carrier shall maintain adequate firefighting equipment at each pump station, terminal, and tank farm. The equipment must be—

(a) In proper operating condition at all times;

(b) Plainly marked so that its identity as firefighting equipment is clear; and

(c) Located so that it is easily accessible during a fire.

§ 195.432 Storage vessels.

Each carrier shall, at intervals not exceeding 12 months, inspect each storage vessel (including atmospheric and pressure tanks).

§ 195.434 Signs.

Each carrier shall maintain signs visible to the public around each pumping station, terminal, or tank farm. Each sign must contain the name of the carrier and an emergency telephone number to contact.

§ 195.436 Security of facilities.

Each carrier shall provide protection for each pumping station, terminal, and tank farm and other exposed facility (such as scraper traps) from vandalism and unauthorized entry.

§ 195.438 Smoking or open flames.

Each carrier shall prohibit smoking and open flames in each pump station area and each terminal or tank farm area where there is a possibility of the leakage of a flammable commodity or of the presence of flammable vapors.

PAGE NUMBER
TYPING GUIDE SHEET

A.2 FOREIGN - TRANSPORTATION OF LIQUIDS BY PIPELINE

Reference list of ligislation and regulations, standards, technical requirements, codes of practice for design construction and operation of oil pipelines in Western Europe[80].

EPA Form 2550-4 (4-80)
TYPING GUIDE SHEET

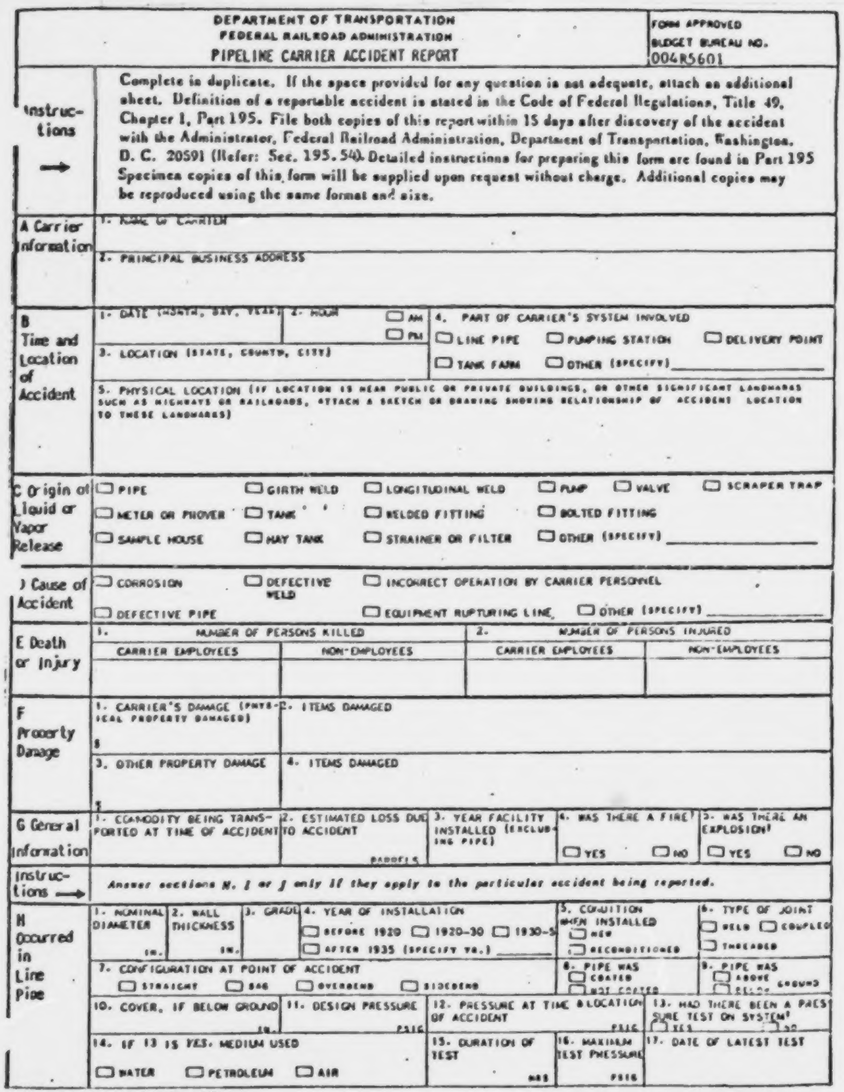
TRANSPORTATION OF LIQUIDS BY PIPELINE (FOREIGN REGULATIONS)

	government legislation/regulations – Law/Decree/Application order ◦ Permit or approval required	Ref.	standards	techn. requirements/code of practice	Ref.
Austria	– Law of 1975.07.3 on transport of products by pipelines	A1		"Austrian Pipeline Code" issued by the Austrian Association for the Mineral Oil Industry, based on IP Code, but not acknowledged by the authorities (Regeln für Bau und Betrieb von Fernleitungen für Erdöl und flüssige Erdölprodukte - 1964)	A2
	◦ Trade Rights Permit (Oesterreichische Gewerbeordnung) from Ministry of Trade				
	◦ Water Rights Permit (Wasserrechtsgesetz 1959, revised in 1969) from Provincial Authority for each Province crossed				
Belgium	– Law of 1965.04.12 on transport by pipes of gaseous products and others	B-1	Minimum design standards, allowable stress, specific limits for construction near to water catchment areas embodied in Decree of 1967.07		
	– Royal Decree of 1967.06.15 dealing with transportation by pipeline of liquid and/or liquefied hydrocarbons other than those cited in the 1965 Law	B-2			
	– Royal Decree of 1967.07.15 specifying security measures to be taken during construction and operation of installations of transportation by pipeline of products affected by the above decree.	B-3			
	◦ Operating permit from special inspectorate after its certification of the completed installation				
France	Pipelines are normally built in accordance with a declaration of "National Interest" according to:		"Rules and Regulations for pipelines carrying liquid hydrocarbons and hydrocarbons liquefied under pressure", Ed. 1968, by Ministry of Industry, "Direction des Carburants" (DICA) This document specifies the negociating procedures as well as the design and construction criteria incorporated in the decrees and "arrêtés" mentioned		F-7
	– Finance Law of 1958.03 supplemented by	F-1			
	– Decree of 1959.05.16 (and Ministerial circular dated 1961.09.14) which sets up the code for "national interest" pipelines	F-2			
	– Decree of 1959.08.14 on safety regulations for pipelines for liquid hydrocarbons or liquefied hydrocarbons under pressure	F-3		Common prescriptions applicable to the contracts of public works signed by the government: "Fascicule 72 – Oil and Gas Pipeline" put into effect by decree dated 1968.10.24 They describe the rules of art generally agreed by the pipeliners	F-8
	– "Arrêté" dated 1959.10.1 and modifying "arrêtés" of 1961.08.11, 1962.07.2, and 1965.11.30 which sets the safety code for liquid pipelines and liquefied petroleum gas pipelines	F-4			
	– Decree of 1961.08.1 modified by decree of 1967.12.10 for the protection of water catchments and location of protected areas	F-5			
	– Ministerial circular dated 1970.05.29 on changing safety category during operations	F-6			
	◦ Approvals from "Direction des Carburants" (DICA), "Service des Mines" and "Préfets" (local councils) for design and operations				

BEGIN FIRST LINE OF TEXT HERE
DROPPED HEAD, BEGIN SECTIONS HERE
CENTER OF PAGE
TOP OF IMAGE AREA
AFTER LAST LINE OF TEXT
PAGE NUMBER
EPA Form 2550-4 (4-80)
TYPING GUIDE SHEET

	government legislation/regulations – Law/Decree/Application order = Permit or approval required	Ref.	standards	techn.requirements/code of practice	Ref.
Germany	= "Planning approval" for each "Land" concerned (Verordnung genehmigungsbedürftige Anlagen 4. August 1960) according to Chapter 16 and 24 of the Industrial Code (Gewerbeordnung)	D-1	DIN 2413 (D.5) Steel pipes, formula for calculating thickness of pipes subjected to internal pressure 1966.06 revised in 1970 and last issued in 1972.06	Guidelines for pipelines for the transportation of hazardous fluids: a) "Richtlinien für Fernleitungen zum befördern gefährdender Flüssigkeiten" (REF), published on 1968.12.6. This document was revised and issued on 1971.109.22 as TRbF 301 (see D.4b)	D-4
	= Permit required for pipelines transporting crude oil, gasoline, diesel oil and fuel oil and other water endangering liquid or gaseous substances (Wasserhaushaltsgesetz – WHG, 2nd amendment of 1964.08.6 = Water endangering substances as specified by regulation (Verordnung über wassergefährdende Stoffe bei der Beförderung in Rohrleitungen, vom 19. Dezember 1973, BGB1I, vom 22. Dezember 1973 p. 1946)	D-2			
	= Water Right Permit (Wasserhaushaltsgesetz - WHG issued by "Land" authorities	D-3	DIN 17172 (D.6) Steel pipes for pipelines for combustible liquids and gases, technical specifications, 1966.10	b) "Technische Regeln für brennbare Flüssigkeiten" (TRbF 301) issued on 1971.10.22 as part of the technical regulations related to combustible liquids; TRbF issued in 1970.06 Amended by 1973.04 and 1974.02	D-4
Netherlands	No specific Law = General approval from the Ministry of Economic Affairs = Technical approval from each of the provincial authorities and the local Councils (polders, dykes, etc.)			Pipeline Code 1972 for the construction and operation of pipelines for the transportation of gases and liquids with requirements put for water protection (pijpleidingcode 1972) published by the Provincial Authorities of South Holland, 1972.01.	NL-1
				Guidelines for oil pipelines (Leidraad voor Oliepijpleidingen) published in 1973 and prepared by a national committee on storage of dangerous substances (COGS). National Pipeline Code for dyke crossing under study by TAW (Technische Adviescommissie voor de Waterkeringen)	NL-2

	government legislation/regulations – Law/Decree/Application order = Permit or approval required	Ref.	standards techn. requirements/code of practice	Ref.
Italy	No specific Law – Ministerial Decree 1966.07.12, revised on 1971.02.23 on technical standards for pipelines carrying liquids and gas across and parallel to railways, tramways and branch lines = Permit for construction and operation from Ministry of Trade and Industry on basis of a general decree of 1934.07.31, "Rules for the Input, Refining, Storage and Distribution of Mineral Oils"	F-1	– Design standards to be discussed with the authorities for each project – Specific technical standards embodied in Decree of 1966.07 ANSI B 31 A are commonly recognized.	
Switzerland	– Federal Law of 1963.10.4, "Pipeline Installations for the Transportation of Liquid or gaseous Fuels" – Application Order dated 1968.09.11 of the above Law – "Arrêté" of the Federal Council of 1968.09.11 on the technical control of the installations of pipeline transportation – Ordinance of 1966.07.1 on safety rules for the installation of pipeline transportation = Federal concession to build and operate a pipeline under the 1963 Federal Law subjected to the above 1966 Ordinance on safety rules	CH-1 CH-2 CH-3 CH-4	"Regulations on the pipeline installations for the transportation of liquid or gaseous fuels" dated 1971.04.30 Federal Board of Energetic Economy. This document brings together the procedures and regulations incorporated in the mentioned Federal legislation.	CH-5
United Kingdom	– Pipe-lines Act 1962 which empowers the Secretary of State for Energy to control all pipeline construction and operation, other than those of the Statutory Undertakings. – Land Drainage Act 1961 – The Petroleum and Submarine Pipe-lines Act 1975 empowers the Secretary of State for Energy to control the construction and use of pipelines in territorial and continental shelf waters, other than a pipeline which has neither initial nor terminal point within those waters. – Coast Protection Act 1949 – Continental Shelf Act 1964 – Town and Country Planning Act 1962, for that part of a submarine pipeline above sea level (LWMOST), provided it is less than 10 miles in length.	UK-1	– British Standard Code of Practice No. CP 2010 "Pipelines" Parts 1 and 2 – Institute of Petroleum Model Code of Safe Practice Petroleum Pipelines - Part 6 – BS 4515. Specification for field welding of carbon steel pipelines	UK 2



DEPARTMENT OF TRANSPORTATION
FEDERAL RAILROAD ADMINISTRATION
PIPELINE CARRIER ACCIDENT REPORT

FORM APPROVED
BUDGET BUREAU NO.
004R5601

Instructions → Complete in duplicate. If the space provided for any question is not adequate, attach an additional sheet. Definition of a reportable accident is stated in the Code of Federal Regulations, Title 49, Chapter 1, Part 195. File both copies of this report within 15 days after discovery of the accident with the Administrator, Federal Railroad Administration, Department of Transportation, Washington, D. C. 20591 (Refer: Sec. 195.54). Detailed instructions for preparing this form are found in Part 195. Specimen copies of this form will be supplied upon request without charge. Additional copies may be reproduced using the same format and size.

A Carrier Information
1. NAME OF CARRIER
2. PRINCIPAL BUSINESS ADDRESS

B Time and Location of Accident
1. DATE (MONTH, DAY, YEAR)
2. HOUR ☐ AM ☐ PM
3. LOCATION (STATE, COUNTY, CITY)
4. PART OF CARRIER'S SYSTEM INVOLVED ☐ LINE PIPE ☐ PUMPING STATION ☐ DELIVERY POINT ☐ TANK FARM ☐ OTHER (SPECIFY) ____
5. PHYSICAL LOCATION (IF LOCATION IS NEAR PUBLIC OR PRIVATE BUILDINGS, OR OTHER SIGNIFICANT LANDMARKS SUCH AS HIGHWAYS OR RAILROADS, ATTACH A SKETCH OR DRAWING SHOWING RELATIONSHIP OF ACCIDENT LOCATION TO THESE LANDMARKS)

C Origin of Liquid or Vapor Release
☐ PIPE ☐ GIRTH WELD ☐ LONGITUDINAL WELD ☐ PUMP ☐ VALVE ☐ SCRAPER TRAP
☐ METER OR PROVER ☐ TANK ☐ WELDED FITTING ☐ BOLTED FITTING
☐ SAMPLE HOUSE ☐ WAY TANK ☐ STRAINER OR FILTER ☐ OTHER (SPECIFY) ____

D Cause of Accident
☐ CORROSION ☐ DEFECTIVE WELD ☐ INCORRECT OPERATION BY CARRIER PERSONNEL
☐ DEFECTIVE PIPE ☐ EQUIPMENT RUPTURING LINE ☐ OTHER (SPECIFY) ____

E Death or Injury

1. NUMBER OF PERSONS KILLED		2. NUMBER OF PERSONS INJURED	
CARRIER EMPLOYEES	NON-EMPLOYEES	CARRIER EMPLOYEES	NON-EMPLOYEES

F Property Damage
1. CARRIER'S DAMAGE (PHYSICAL PROPERTY DAMAGED) $
2. ITEMS DAMAGED
3. OTHER PROPERTY DAMAGE $
4. ITEMS DAMAGED

G General Information
1. COMMODITY BEING TRANSPORTED AT TIME OF ACCIDENT
2. ESTIMATED LOSS DUE TO ACCIDENT BARRELS
3. YEAR FACILITY INSTALLED (EXCLUDING PIPE)
4. WAS THERE A FIRE? ☐ YES ☐ NO
5. WAS THERE AN EXPLOSION? ☐ YES ☐ NO

Instructions → *Answer sections H, I or J only if they apply to the particular accident being reported.*

H Occurred in Line Pipe
1. NOMINAL DIAMETER IN.
2. WALL THICKNESS IN.
3. GRADE
4. YEAR OF INSTALLATION ☐ BEFORE 1920 ☐ 1920-30 ☐ 1930-35 ☐ AFTER 1935 (SPECIFY YR.) ____
5. CONDITION WHEN INSTALLED ☐ NEW ☐ RECONDITIONED
6. TYPE OF JOINT ☐ WELD ☐ COUPLED ☐ THREADED
7. CONFIGURATION AT POINT OF ACCIDENT ☐ STRAIGHT ☐ SAG ☐ OVERBEND ☐ SIDEBEND
8. PIPE WAS ☐ COATED ☐ NOT COATED
9. PIPE WAS ☐ ABOVE GROUND ☐ BELOW GROUND
10. COVER, IF BELOW GROUND IN.
11. DESIGN PRESSURE PSIG
12. PRESSURE AT TIME & LOCATION OF ACCIDENT PSIG
13. HAD THERE BEEN A PRESSURE TEST ON SYSTEM? ☐ YES ☐ NO
14. IF 13 IS YES, MEDIUM USED ☐ WATER ☐ PETROLEUM ☐ AIR
15. DURATION OF TEST HRS
16. MAXIMUM TEST PRESSURE PSIG
17. DATE OF LATEST TEST

DOT Form 7000-1 (8-69)

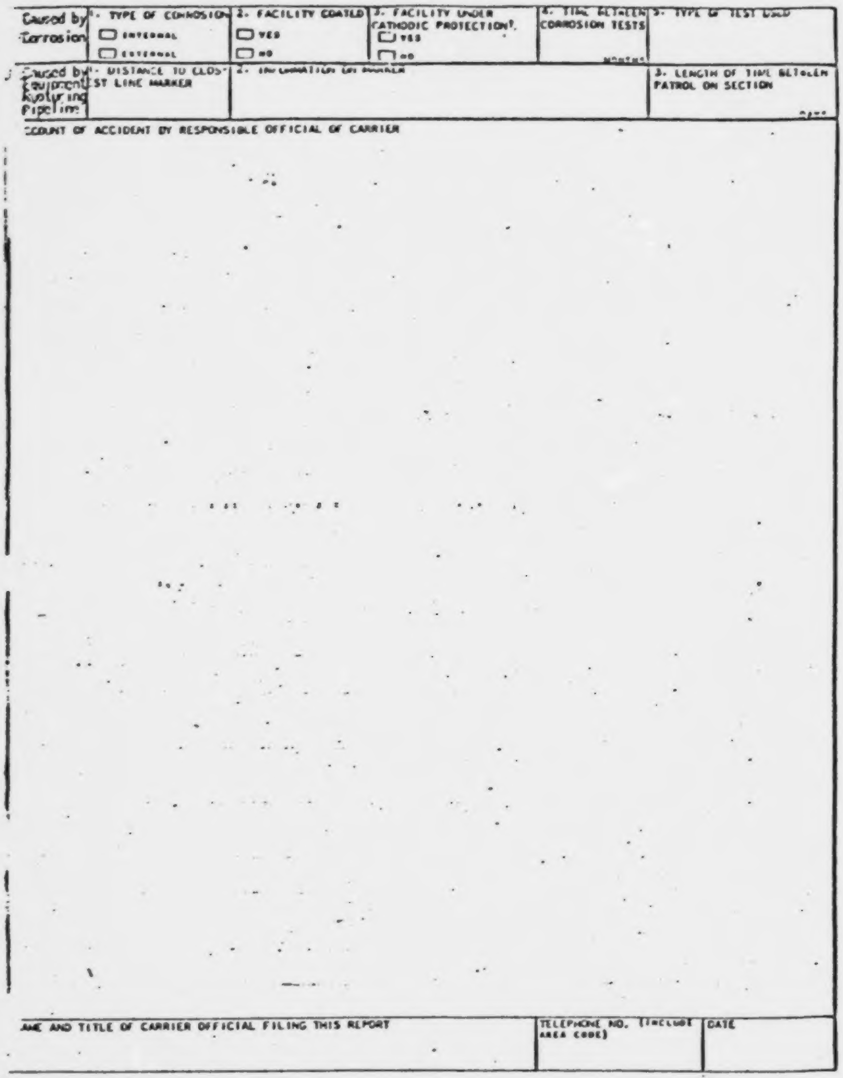
Figure A-1. DOT 7000-1 (Page 1).

BEGIN FIRST LINE OF TEXT HERE

CENTER OF PAGE

TOP OF IMAGE AREA

DROPPED HEAD. BEGIN SECTIONS HERE



Caused by Corrosion	1. TYPE OF CORROSION ☐ INTERNAL ☐ EXTERNAL	2. FACILITY COATED ☐ YES ☐ NO	3. FACILITY UNDER CATHODIC PROTECTION? ☐ YES ☐ NO	4. TIME BETWEEN CORROSION TESTS MONTHS	5. TYPE OF TEST USED
Caused by Equipment Rupturing Pipeline	1. DISTANCE TO CLOSEST LINE MARKER	2. INFORMATION ON MARKER			3. LENGTH OF TIME BETWEEN PATROL ON SECTION DAYS

ACCOUNT OF ACCIDENT BY RESPONSIBLE OFFICIAL OF CARRIER

NAME AND TITLE OF CARRIER OFFICIAL FILING THIS REPORT	TELEPHONE NO. (INCLUDE AREA CODE)	DATE

Figure A-2. DOT 7000-1 (Page 2).

BELOW LAST LINE OF TEXT

BOTTOM OF IMAGE AREA

PAGE NUMBER

EPA Form 2350-4 (4-80)

TYPING GUIDE SHEET

References [a]

Austria A-1 Bundesgesetz von 3. Juli 1975 über die gewerbsmäszige Beförderung von Gütern in Rohrleitungen (Rohrleitungsgesetz).
Ausgegeben am 31. Juli 1975 - Nr. 411 p 1759 - 1771

A-2 Fachverband der Erdölindustrie Oesterreichs.
"Regeln für Bau und Betrieb von Fernleitungen für Erdöl und Flüssige Erdölprodukte - 1964"

Belgium B-1 Loi du 12 Avril 1965 relative au transport de produits gazeux et autres par canalisations - Moniteur Belge du 7 Mai 1965.

B-2 Ministère des Affaires Economiques et Ministère des Transports et PTT.

a. Décret Royal du 15 Juin 1967 Moniteur Belge 137:118, 22 Juin 1967, pp. 6753-6754.
Extension de certaines dispositions de la loi du 12 Avril 1965 relative au transport de produits gazeux et autres par canalisations, au transport par canalisations d'hydrocarbures liquides et/ou d'hydrocarbures liquéfiés, autres que ceux visés par l'article 1er, littèra a, de cette loi.

b. Décret Royal du 25 Juillet 1967 Moniteur Belge 137:169, 5 Septembre 1967, pp. 9312-9323.
Détermination des mesures de sécurité à prendre lors de l'établissement et dans l'exploitation des installations de transport par canalisations d'hydrocarbures liquides et/ou d'hydrocarbures liquéfiés, autres que ceux visés par l'article 1er, littèra a, de la loi du 12 Avril 1965, relative au transport de produits gazeux et autres par canalisations.

France F-1 Loi de Finance no. 58-336 du 29 Mars 1958 (article II).
Journal Officiel (J.O.) du 1 avril 1958 p. 3170.

F-2 Décret nr. 59 645 du 16 Mai 1959 J.O. du 21 Mai 1959 p. 5178-5182, modifié par décret no. 66-550 du 25 Juillet 1966 (art. 7 et 33) et Circulaire Ministérielle du 14 Septembre 1961 nr. 2.905

F-3 Décret nr. 59-998 du 14 Août 1959 J.O. du 23 Août 1959 p. 8412.

F-4 Arrêté du 1er Octobre 1959 J.O. du 3 Octobre 1959 p. 9557 et arrêtés modificatifs du 11 Août 1961 (art. 24 liquides), 2 Juillet 1962 (art. 49, liquides; art. 47, liquéfiés) et 30 Novembre 1965 (art. 7, 18 et 48, liquides; art. 10 et 14, liquéfiés).

F-5 Décret nr. 61-859 du 1 Août 1961 J.O. du 5 Août 1961 modifié par décret nr. 67-1093 du 15 Décembre 1967 J.O. du 10 Décembre 1967.

F-6 Circulaire Ministérielle du 29 Mai 1970 (ministère du Développement Industriel et Scientifique, Direction des Carburants) nr. 3145 en application du décret nr. 59-998 du 14 Août 1959.

F-7 Ministère de l'industrie. Direction des Carburants "Législation et Règlementation des Pipelines à hydrocarbures liquides ou liquéfiés sous pression". Imprimerie Nationale. Paris, 1968, pp. 1-106.

F-8 Marché de l'Etat. Marché des Travaux Publics.
Cahier des prescriptions communes "Fascicule nr. 72: Oléoducs – Gazoducs" mis en application par décret no. 68.1003 du 24 Octobre 1968.

Germany D-1 Gewerbeordnung (GewO) § 16 in der Neufassung vom 1. Juni 1960.

D-2 Verordnung über die Errichtung und den Betrieb von Anlagen zur Lagerung, Abfüllung und Beförderung brennbarer Flüssigkeiten zu Lande (Verordnung über brennbare Flüssigkeiten – VbF vom 5. Juni 1970 (BGBl. 1S. 689). § 9 Abs. 1 nr. 4 und Abs. 2 und 13 Abs. 1.

D-3 Gesetz zur Ordnung des Wasserhaushalts (Wasserhaushaltsgesetz – WHG) vom 27. Juli 1957 (BGBl 1 S. 1110), zuletzt geändert durch das Gesetz vom 6. August 1964 und vom 23. Juni 1970 (BGBl. 1 S. 805), § 19 a ff.

D-4a Bundesministerium für Arbeit, Bonn.
RFF: Richtlinie für Fernleitungen zum Befördern gefährdender Flussigkeiten.
Bek. des BMA vom 6. Dezember 1968. IIIb4-3893.016-4940/68. Arbeitsschutz nr. 12/1968. pp. 347-365.

---

[a] Reference 30

TYPING GUIDE SHEET

D-4b Technische Regeln für brennbare Flüssigkeiten – TRbF – aufgestellt vom Deutschen Ausschuss für brennbare Flüssigkeiten (DAbF) und veröffentlicht vom Bundesminister für Arbeit und Sozialordnung im Bundesarbeitsblatt, Fachteil "Arbeitsschutz" (nach der Allgemeinen Verwaltungsvorschrift zu § 6 der Verordnung über brennbare Flüssigkeiten – VbF – vom 12. Mai 1970).

TrbF 301 Richtlinie für Fernleitungen zum Befördern gefährdender Flüssigkeiten (RFF) Ausgabe September 1971. Revised on 1973.04.9 and 1974.04.1.

D-5 DIN 2413 Stahlrohre. Berechnung der Wanddicke gegen Innendruck, in der Fassung vom Juni 1972
DK 621.643.23: 669.14-462.

D-6 DIN 17 172 Stahlrohre für Fernleitungen für brennbare Flüssigkeiten und Gase, Technische Lieferbedingungen, Oktober 1966.

Italy I-1 Decreto Ministeriale 12 luglio 1966 – Norme Tecniche per gli attraversamenti ed i parallelismi di condotte di liquidie e gas con linee ferroviarie, tranviarie et con binari di raccordo. Gazetto Ufficiale nr. 221 del 6 settembre 1966, pp. 3-15.
Revised 23 febbraio 1971 – Gazetto Ufficiale del 7 maggio 1971.

Netherlands NL-1 Provinciale Waterstaat in Zuid-Holland. "Pijpleidingcode 1972". (januari 1972 - revisie 3, 1 januari 1974) eisen te stellen aan pijpleidingen voor het transport van gassen en vloeistoffen met betrekking tot de Waterstaatkundige veiligheid.
Studiegroep Pijpleidingen voor gassen en vloeistoffen.

NL-2 Commissie Opslag Gevaarlijke Stoffen (COGS).
"Leidraad voor Oliepijpleidingen" – 1973 published by Ministry of Social Affairs (Directoraat-Generaal van de Arbeid van het Ministerie van Sociale Zaken, Voorburg).

Switzerland CH-1 Loi Fédérale du 4 Avril 1969 sur les installations de transport par conduites de combustibles ou carburants liquides ou gazeux (loi sur les installations de transport par conduites). RO. 1964 95

CH-2 Ordonnance d'exécution du 11 Septembre 1968 de la loi fédérale sur les installations de transport par conduites de combustibles ou carburants liquides ou gazeux.
RO. 1968 1162 1404

CH-3 Arrêté du Conseil Fédéral du 11 Septembre 1968 concernant la surveillance technique des installations de transport par conduites. RO. 1968 1185.

CH-4 Ordonnance du 1er Juillet 1966 concernant les prescriptions de sécurité our les installations de transport par conduites. RO. 1966 497.

CH-5 Office Fédéral de l'Economie Energique.
Prescriptions sur les installations de transport par conduites de combustibles ou carburants liquides ou gazeux. Etat le 30 Avril 1971 pp. 1-71.

United Kingdom UK-1 Her Majesty's Stationary Office, London. Pipelines Act, 1962. 10 & 11 Eliz 2. CH 58. pp. 1-66

UK-2 British Standards Institution (BSI) London. Code of Practice for Pipelines. CP 2010.
Part 1 "Installation of pipelines in land" – 1966. pp. 1-22
Part 2 "Design and construction of steel pipelines in land" 1970. pp. 1-56.

USA (For information)

ANSI: American National Standards Institute.
ANSI B 31.4 "Liquid Petroleum Transportation Piping Systems".

API: American Petroleum Institute, New York.
API-5L: Specification for Line Pipe
API-5LX: Specification for high-test Line Pipe
API-5LS: Specification for spiral welded Line Pipe
API-1104: Specification for Field welding of pipelines
API-1105: Recommended Practice on construction of steel pipelines

Code of Federal Regulations
"Minimal Federal Safety Standards for Liquid Pipelines" related to transportation of liquids by pipeline. (Part 195, Title 49 of the Code).

APPENDIX B

PIPELINE MILEAGE DATA

Petroleum pipelining activity in the United States,
January 1, 1974 to January 1, 1977

(Miles)

State	Total in place Jan. 1, 1974	Pipe laid		Pipe taken up	Total in place Jan. 1, 1977
		New	Second-hand		
Alabama	1,759	87	11	197	1,660
Alaska	124	70	24	25	193
Arizona	1,352	-	11	8	1,355
Arkansas	2,997	546	9	481	3,071
California	10,183	814	136	781	10,352
Colorado	2,180	328	37	149	2,396
Connecticut	92	1	1	-	94
Delaware	6	-	-	3	3
Florida	273	19	9	13	288
Georgia	1,886	138	-	-	2,024
Idaho	633	-	-	-	633
Illinois	11,405	661	320	1,472	10,914
Indiana	4,629	404	612	1,093	4,552
Iowa	3,951	473	446	289	4,581
Kansas	r/ 16,343	2,147	792	2,130	17,152
Kentucky	2,326	370	22	274	2,444
Louisiana	8,791	1,033	731	1,095	9,460
Maine	354	-	-	1	353
Maryland and District of Columbia	220	-	-	1	219
Massachusetts	r/ 272	2	4	36	242
Michigan	3,929	264	1,338	670	4,861
Minnesota	r/ 2,869	-	-	28	2,841
Mississippi	3,389	10	82	235	3,246
Missouri	6,928	375	367	528	7,142
Montana	2,806	32	517	123	3,232
Nebraska	3,283	79	72	117	3,317
Nevada	198	-	78	1	275
New Hampshire	108	-	82	-	190
New Jersey	r/ 453	61	7	27	494
New Mexico	5,927	580	820	367	6,960
New York	1,939	14	3	370	1,586
North Carolina	900	6	28	38	896
North Dakota	1,741	86	45	99	1,773
Ohio	6,965	610	211	1,262	6,524
Oklahoma	r/ 20,762	2,898	745	3,695	20,710
Oregon	673	-	-	259	414
Pennsylvania	8,038	907	105	953	8,097
Rhode Island	17	-	-	-	17
South Carolina	669	-	-	1	668
South Dakota	642	-	-	-	642
Tennessee	707	32	-	-	739
Texas	r/ 66,310	3,900	1,570	5,814	65,966
Utah	r/ 1,068	47	46	23	1,118
Vermont	177	-	-	-	177
Virginia	834	-	-	10	824
Washington	760	27	7	11	783
West Virginia	r/ 3,848	356	21	r/ 714	3,511
Wisconsin	942	-	-	16	926
Wyoming	6,897	524	327	597	7,151
Total	r/ 223,535	17,901	9,636	24,006	227,066

r/ Revised.

Petroleum pipelining activity in the United States, January 1, 1971 to January 1, 1974

(Miles)

State	Total in place Jan. 1, 1971	Pipe laid		Pipe taken up	Total in place Jan. 1, 1974
		New	Second-hand		
Alabama	1,237	421	101	-	1,759
Alaska	87	35	4	2	124
Arizona	1,071	272	9	-	1,352
Arkansas	2,397	565	408	373	2,997
California	r/ 9,858	717	760	1,152	10,183
Colorado	1,756	275	236	87	2,180
Connecticut	92	-	-	-	92
Delaware	3	-	3	-	6
Florida	87	213	-	27	273
Georgia	1,728	184	4	30	1,886
Idaho	640	6	-	13	633
Illinois	r/ 11,096	1,254	817	1,762	11,405
Indiana	4,495	283	72	221	4,629
Iowa	3,889	376	-	314	3,951
Kansas	16,013	500	635	1,241	15,907
Kentucky	2,511	8	1,310	1,503	2,326
Louisiana	7,956	1,296	834	1,295	8,791
Maine	353	-	1	-	354
Maryland and District of Columbia	219	-	1	-	220
Massachusetts	242	94	11	-	347
Michigan	3,744	156	297	268	3,929
Minnesota	2,955	107	106	69	3,099
Mississippi	3,058	435	78	182	3,389
Missouri	6,295	562	336	265	6,928
Montana	3,054	127	188	563	2,806
Nebraska	3,341	149	182	389	3,283
Nevada	328	189	2	321	198
New Hampshire	108	-	38	38	108
New Jersey	568	2	1	99	472
New Mexico	5,941	1,139	223	1,376	5,927
New York	1,673	74	247	55	1,939
North Carolina	834	70	-	4	900
North Dakota	1,664	63	113	99	1,741
Ohio	6,909	420	123	487	6,965
Oklahoma	22,308	1,401	292	3,454	20,547
Oregon	689	11	12	39	673
Pennsylvania	8,291	87	162	502	8,038
Rhode Island	17	-	-	-	17
South Carolina	635	71	-	37	669
South Dakota	640	-	37	35	642
Tennessee	629	78	1	1	707
Texas	65,259	1,436	3,429	4,652	65,472
Utah	1,042	39	504	244	1,341
Vermont	177	-	-	-	177
Virginia	822	8	11	7	834
Washington	762	129	3	134	760
West Virginia	3,612	41	548	661	3,540
Wisconsin	942	-	1	1	942
Wyoming	6,644	664	186	597	6,897
Total	r/ 218,671	13,957	12,326	22,599	222,355

TYPING GUIDE SHEET

Petroleum pipelining activity in the United States, January 1, 1968 to January 1, 1971

(Miles)

State	Total in place Jan. 1, 1968	Pipe laid		Pipe taken up	Total in place Jan. 1, 1971
		New	Second-hand		
Alabama	1,121	94	22	-	1,237
Alaska	74	5	20	12	87
Arizona	1,064	-	9	2	1,071
Arkansas	2,334	258	43	238	2,397
California	9,536	641	402	711	9,868
Colorado	1,739	153	125	261	1,756
Connecticut	91	1	-	-	92
Delaware	3	-	-	-	3
Florida	35	2	50	-	87
Georgia	1,567	165	129	133	1,728
Idaho	639	-	1	-	640
Illinois	10,707	1,262	91	1,041	11,019
Indiana	4,309	386	23	223	4,495
Iowa	3,169	755	3	38	3,889
Kansas	15,486	1,753	236	1,462	16,013
Kentucky	2,519	93	6	107	2,511
Louisiana	7,573	1,015	322	954	7,956
Maine	544	3	8	202	353
Maryland and District of Columbia	235	-	1	17	219
Massachusetts	239	1	28	26	242
Michigan	3,797	562	129	744	3,744
Minnesota	2,909	46	-	-	2,955
Mississippi	2,356	758	14	70	3,058
Missouri	6,434	112	5	256	6,295
Montana	2,671	497	162	276	3,054
Nebraska	3,114	422	22	217	3,341
Nevada	331	-	8	11	328
New Hampshire	109	-	-	1	108
New Jersey	545	2	27	6	568
New Mexico	5,833	304	829	1,025	5,941
New York	1,868	23	68	286	1,673
North Carolina	833	1	5	5	834
North Dakota	1,728	87	6	157	1,664
Ohio	7,168	687	81	1,027	6,909
Oklahoma	22,250	1,313	392	1,647	22,308
Oregon	402	286	1	-	689
Pennsylvania	8,943	212	171	1,035	8,291
Rhode Island	17	-	1	1	17
South Carolina	567	74	1	7	635
South Dakota	575	65	-	-	640
Tennessee	519	112	1	3	629
Texas	60,316	6,978	2,806	4,841	65,259
Utah	1,362	45	6	371	1,042
Vermont	177	-	-	-	177
Virginia	807	18	1	4	822
Washington	672	155	1	66	762
West Virginia	3,714	99	147	348	3,612
Wisconsin	594	346	2	-	942
Wyoming	5,883	957	225	421	6,644
Total	209,478	20,748	6,630	18,252	218,604

TYPING GUIDE SHEET

Petroleum pipelining activity in the United States, January 1, 1974 to January 1, 1977

(Miles)

Size (inches)	Gathering Lines			Crude-oil trunklines		
	New pipe laid	Secondhand pipe laid	Pipe taken up	New pipe laid	Secondhand pipe laid	Pipe taken up
2	793	416	2,181	6	6	28
3	571	551	1,890	4	18	33
4 1/	1,550	1,250	3,105	153	265	502
6 2/	821	529	1,133	435	462	1,047
8	486	414	1,018	881	699	2,701
10	120	192	177	773	123	578
12	130	252	54	257	207	491
14	4	5	-	-	7	16
16	7	5	-	198	250	141
18	-	-	-	17	34	83
20	2	-	12	386	58	165
22	2	-	-	14	414	33
24	-	-	-	723	51	1
Over 24	6	42	27	1,063	96	59
Total	4,492	3,656	9,597	4,910	2,690	5,878

Size (inches)	Products trunklines			Total all pipelines		
	New pipe laid	Secondhand pipe laid	Pipe taken up	New pipe laid	Secondhand pipe laid	Pipe taken up
2	7	10	48	806	432	2,257
3	48	11	117	623	580	2,040
4 1/	276	235	486	1,979	1,750	4,093
6 2/	2,350	585	2,156	3,606	1,576	4,336
8	2,673	304	3,113	4,040	1,417	6,832
10	1,623	947	1,224	2,516	1,262	1,979
12	703	660	672	1,090	1,119	1,217
14	255	295	519	259	307	535
16	157	106	140	362	361	281
18	59	15	49	76	49	132
20	139	31	4	527	89	181
22	-	-	-	16	414	33
24	-	23	-	723	74	1
Over 24	209	68	3	1,278	206	89
Total	8,499	3,290	8,531	17,901	9,636	24,006

1/ Includes a small amount of 5-inch pipe in trunklines.
2/ Includes a small amount of 7-inch pipe in trunklines.

TYPING GUIDE SHEET

BEGIN FIRST LINE OF TEXT HERE
CENTER OF PAGE
TOP OF IMAGE AREA
DROPPED HEAD; BEGIN SECTIONS HERE

Petroleum pipelining activity in the United States, January 1, 1971 to January 1, 1974

(Miles)

Size (inches)	Gathering lines			Crude-oil trunklines		
	New pipe laid	Secondhand pipe laid	Pipe taken up	New pipe laid	Secondhand pipe laid	Pipe taken up
2	488	1,024	2,428	16	9	62
3	423	1,028	1,597	54	290	207
4 1/	1,287	2,305	3,674	115	272	244
6 2/	505	336	1,899	689	596	1,027
8	337	910	817	717	1,307	821
10	97	66	95	167	155	1,149
12	185	10	363	718	206	837
14	2	-	-	136	-	109
16	4	1	-	103	120	185
18	-	-	-	46	44	1
20	1	-	7	157	6	308
22	1	-	-	28	83	57
24	-	-	-	3	-	26
Over 24	4	-	-	130	32	59
Total	3,334	5,680	10,880	3,079	3,120	5,092

Size (inches)	Products trunklines			Total all pipelines		
	New pipe laid	Secondhand pipe laid	Pipe taken up	New pipe laid	Secondhand pipe laid	Pipe taken up
2	8	16	22	512	1,049	2,512
3	298	63	201	775	1,381	2,005
4 1/	136	290	322	1,538	2,867	4,240
6 2/	1,133	553	1,850	2,327	1,485	4,776
8	2,539	474	2,425	3,593	2,691	4,063
10	1,034	660	450	1,298	881	1,694
12	509	30	914	1,412	246	2,114
14	358	156	169	496	156	278
16	263	269	142	370	390	327
18	260	-	2	306	44	3
20	172	110	116	330	116	431
22	-	-	-	29	83	57
24	-	-	-	3	-	26
Over 24	834	905	14	968	937	73
Total	7,544	3,526	6,627	13,957	12,326	22,599

1/ Includes a small amount of 5-inch pipe in trunklines.
2/ Includes a small amount of 7-inch pipe in trunklines.

BEGIN LAST LINE OF TEXT
PAGE NUMBER
EPA Form 2350-8 (8-80)
TYPING GUIDE SHEET

Petroleum pipelining activity in the United States, January 1, 1968 to January 1, 1971

(Miles)

Size (inches)	Gathering lines			Crude-oil trunklines		
	New pipe laid	Secondhand pipe laid	Pipe taken up	New pipe laid	Secondhand pipe laid	Pipe taken up
2	696	82	1,633	106	53	12
3 1/	580	259	1,653	71	40	48
4 2/	1,664	1,605	3,894	908	451	344
6 3/	573	139	1,448	1,380	513	1,355
8	99	370	595	848	445	1,549
10	88	19	81	558	113	1,002
12	9	184	50	790	225	197
14	-	-	-	18	22	17
16	37	1	43	342	17	70
18	-	-	-	-	11	1
20	-	-	-	336	86	147
22	-	-	-	5	2	2
24	-	-	-	7	3	3
Over 24	-	-	-	1,646	9	17
Total	3,746	2,659	9,397	7,015	1,990	4,764

Size (inches)	Products trunklines			Total all pipelines		
	New pipe laid	Secondhand pipe laid	Pipe taken up	New pipe laid	Secondhand pipe laid	Pipe taken up
2	42	128	90	844	263	1,735
3 1/	81	121	221	732	420	1,922
4 2/	553	237	438	3,125	2,293	4,676
6 3/	2,012	183	1,465	3,965	835	4,268
8	2,791	714	693	3,738	1,529	2,837
10	1,622	118	142	2,268	250	1,225
12	1,590	59	106	2,389	468	353
14	211	106	5	229	128	22
16	465	110	413	844	128	526
18	95	23	136	95	34	137
20	91	4	263	427	90	410
22	-	-	-	5	2	2
24	-	-	-	7	3	3
Over 24	434	178	119	2,080	187	136
Total	9,987	1,981	4,091	20,748	6,630	18,252

1/ Includes a small amount of 2-inch pipe in trunklines.
2/ Includes a small amount of 5-inch pipe in trunklines.
3/ Includes a small amount of 7-inch pipe in trunklines.

Mileage of gathering lines in the United States as of January 1, 1971
(Miles)

State	Size (inches)									
	2	3	4/	6 2/	8 3/	10	12 3/	Over 12	Total	
									Jan. 1, 1971	Jan. 1, 1968
Alabama	2	-	18	9	11	-	-	-	40	18
Arkansas	239	90	457	48	10	1	-	-	845	776
California	78	180	596	1,001	486	204	27	2	2,574	2,722
Colorado	22	19	101	113	96	-	-	3	354	546
Illinois	653	1,154	1,360	232	67	29	1	-	3,496	3,720
Indiana	224	331	202	26	-	-	-	-	783	916
Kansas	748	1,377	2,707	677	495	35	61	-	6,100	6,934
Kentucky	923	518	466	201	34	2	-	1	2,145	2,198
Louisiana	393	89	612	440	305	135	311	45	2,330	2,493
Michigan	33	174	266	48	11	-	-	-	532	1,027
Mississippi	121	59	257	82	52	2	2	13	588	466
Montana	91	177	209	270	16	-	1	-	764	746
Nebraska	12	10	99	206	61	-	-	-	388	581
New Mexico	67	268	2,125	587	229	12	5	-	3,293	3,224
New Jersey	-	-	-	12	7	-	-	-	19	-
New York	310	115	7	-	-	-	-	-	432	550
North Dakota	11	91	266	39	-	-	-	-	407	482
Ohio	991	391	335	145	1	-	-	-	1,863	1,854
Oklahoma	2,659	2,197	4,339	2,084	668	110	274	-	12,331	12,544
Pennsylvania	2,059	632	197	27	1	-	-	-	2,916	3,419
Texas	2,568	2,672	12,237	4,317	1,884	325	75	8	24,086	23,704
Utah	-	1	45	43	22	9	5	-	125	290
West Virginia	2,187	530	259	194	3	-	-	-	3,173	3,275
Wyoming	72	91	609	479	257	8	32	-	1,548	1,639
Total Jan. 1, 1971	14,463	11,166	27,769	11,280	4,716	872	794	72	71,132	-
Total Jan. 1, 1968	15,318	11,980	28,394	12,016	4,842	846	611	117	-	74,124

1/ Includes a small amount of 5-inch pipe.
2/ Includes a small amount of 7-inch pipe.
3/ Includes a small amount of 11-inch pipe.

TYPING GUIDE SHEET

Mileage of gathering lines in the United States as of January 1, 1974
(Miles)

State	Size (inches)								Total	
	2	3	4 1/	6 2/	8 3/	10 4/	12	Over 12	Jan. 1, 1974	Jan. 1, 1971
Alabama	2	2	28	22	11	-	-	-	65	40
Alaska	-	-	-	-	-	23	-	-	23	-
Arizona	-	-	4	4	-	-	-	-	8	-
Arkansas	284	118	588	61	10	1	-	-	1,062	865
California	131	220	545	878	457	202	24	3	2,460	2,574
Colorado	8	60	155	118	85	-	5	3	434	354
Florida	-	-	-	3	6	4	-	-	13	-
Illinois	564	998	1,146	203	26	29	1	-	2,967	3,496
Indiana	164	275	180	17	-	-	-	-	636	783
Kansas	751	1,429	2,713	719	484	50	61	-	6,207	6,100
Kentucky	819	445	423	-	161	31	-	1	1,880	2,145
Louisiana	306	111	788	405	315	135	144	43	2,247	2,330
Michigan	35	207	400	60	26	-	-	-	728	532
Mississippi	102	49	221	57	14	2	2	12	459	588
Montana	76	187	260	322	15	-	1	-	861	764
Nebraska	5	17	100	177	51	-	-	-	350	388
New Jersey	-	-	-	12	7	-	-	-	19	19
New Mexico	133	312	2,063	557	206	12	5	-	3,288	3,293
New York	369	115	6	-	-	-	-	-	490	432
North Dakota	11	94	278	82	13	-	-	-	478	407
Ohio	1,001	384	323	146	1	-	-	-	1,855	1,863
Oklahoma	2,234	2,060	3,644	1,395	434	135	260	-	10,162	12,331
Pennsylvania	2,048	616	193	27	1	-	-	-	2,885	2,916
Texas	2,351	2,615	12,660	4,227	2,534	305	86	16	24,794	24,086
Utah	-	1	48	47	21	9	5	-	131	125
West Virginia	2,104	540	218	174	3	-	-	-	3,039	3,173
Wyoming	49	165	703	509	265	2	32	-	1,725	1,548
Total January 1, 1974	13,547	11,020	27,687	10,222	5,146	940	626	78	69,266	-
Total January 1, 1971	14,463	11,166	27,769	11,280	4,716	872	754	112	-	71,132

1/ Includes a small amount of 5-inch pipe.
2/ Includes a small amount of 7-inch pipe.
3/ Includes a small amount of 9-inch pipe.
4/ Includes a small amount of 11-inch pipe.

Mileage of gathering lines in the United States as of January 1, 1977

(Miles)

State	Size (inches)									
	2	3	4 1/	6 2/	8 3/	10 4/	12	Over 12	Total	
									Jan. 1, 1977	Jan. 1, 1974
Alabama	-	-	19	21	-	-	-	-	40	65
Alaska	-	-	-	-	23	-	-	-	23	23
Arizona	-	-	-	-	-	-	-	-	-	8
Arkansas	342	127	568	53	-	-	-	-	1,090	1,062
California	288	250	588	896	474	182	13	-	2,691	2,460
Colorado	26	75	167	121	88	-	10	3	490	436
Florida	-	-	-	9	6	4	-	-	19	13
Illinois	454	902	1,269	210	33	29	1	-	2,898	2,967
Indiana	126	226	171	18	-	-	-	-	541	636
Kansas	563	1,357	2,819	818	650	38	153	2	6,400	6,207
Kentucky	749	410	393	-	138	-	-	2	1,692	1,880
Louisiana	300	134	739	539	468	208	358	30	2,776	2,247
Michigan	35	318	485	82	47	45	20	25	1,057	728
Mississippi	111	40	190	13	50	2	2	13	421	459
Montana	49	129	301	319	48	-	-	-	846	861
Nebraska	5	17	100	176	52	-	-	-	350	350
New Jersey	-	-	-	-	-	-	-	-	-	
New Mexico	131	332	2,329	539	223	56	5	-	3,615	r/ 3,288
New York	277	46	7	-	-	-	-	-	330	490
North Dakota	11	83	304	94	15	-	-	-	507	478
Ohio	830	263	249	106	42	-	41	-	1,511	1,855
Oklahoma	1,880	1,908	3,185	1,452	497	73	229	-	9,226	10,162
Pennsylvania	1,913	463	173	17	-	-	-	-	2,566	2,885
Texas	2,439	2,657	12,313	4,189	1,877	425	88	37	24,025	24,794
Utah	-	1	44	60	21	9	3	-	138	131
West Virginia	1,988	364	209	119	3	-	-	-	2,683	3,039
Wyoming	58	170	760	574	268	2	31	-	1,863	1,725
Total January 1, 1977	12,575	10,252	27,382	10,425	5,023	1,075	954	112	67,798	-
Total January 1, 1974	13,567	11,020	27,687	r/ 10,210	r/ 5,139	940	626	78	-	r/ 69,247

1/ Includes a small amount of 5-inch pipe.
2/ Includes a small amount of 7-inch pipe.
3/ Includes a small amount of 9-inch pipe.
4/ Includes a small amount of 11-inch pipe.
r/ Revised.

EPA Form 2203-4 (4-80)

TYPING GUIDE SHEET

BEGIN FIRST LINE OF TEXT HERE
CENTER OF PAGE
TOP OF IMAGE AREA
DROPPED HEAD; BEGIN SECTIONS HERE

Mileage of product pipelines in the United States as of January 1, 1971

[Miles]

State	Size (inches)													
	Under 4	4 1/	6 2/	8	10	12	14	16	18	20	22	24 (and over)	Total	
													Jan. 1, 1971	Jan. 1, 1968
Alabama	-	-	56	85	18	402	-	2	310	-	-	290	1,163	1,069
Alaska	-	-	8	-	-	-	-	-	-	-	-	-	8	-
Arizona	-	-	173	261	-	260	-	-	-	-	-	-	694	696
Arkansas	7	20	37	57	236	248	-	1	-	297	-	-	901	901
California	160	343	495	963	383	302	175	63	-	-	-	-	2,841	2,603
Colorado	-	-	411	87	-	-	-	-	-	-	-	-	498	502
Connecticut	-	-	22	-	6	64	-	-	-	-	-	-	92	91
Delaware	-	-	-	-	-	-	-	-	-	-	-	3	3	3
Florida	-	-	26	24	37	-	-	-	-	-	-	-	87	35
Georgia	-	43	197	685	218	106	168	-	12	-	-	322	1,728	1,567
Idaho	-	13	-	548	79	-	-	-	-	-	-	-	640	639
Illinois	1	1	266	1,272	516	807	438	160	3	-	-	-	3,444	3,101
Indiana	6	5	103	1,009	456	300	302	102	-	195	-	-	2,378	2,137
Iowa	6	2	1,636	1,157	292	850	-	84	-	-	-	-	3,867	3,103
Kansas	-	206	1,361	2,662	972	710	-	185	-	-	-	-	5,976	6,390
Kentucky	-	-	49	-	1	-	-	-	-	-	-	-	50	49
Louisiana	7	261	477	302	231	225	-	-	112	142	-	202	2,259	2,069
Maine	-	-	136	-	-	-	-	-	-	-	-	-	136	323
Maryland and District of Columbia	-	-	59	26	-	30	-	-	-	-	-	98	219	335
Massachusetts	-	28	190	10	-	16	-	-	-	-	-	-	262	239
Michigan	1	-	259	472	282	166	-	330	-	-	-	-	1,610	1,271
Minnesota	-	14	434	906	137	291	-	-	-	-	-	-	1,772	1,759
Mississippi	-	-	-	90	-	321	-	-	332	-	-	180	1,123	934
Missouri	10	-	119	1,623	822	412	-	62	-	70	-	-	3,118	3,021
Montana	2	4	141	379	443	-	-	56	-	-	-	-	1,023	967
Nebraska	-	12	1,222	890	38	151	-	-	-	-	-	-	2,313	1,916
Nevada	-	8	82	237	-	1	-	-	-	-	-	-	328	331
New Jersey	2	-	136	39	13	43	79	130	2	-	-	97	549	545
New Mexico	82	-	228	732	-	163	-	-	-	-	-	-	1,205	1,130
New York	1	17	386	392	187	71	86	12	-	-	-	-	1,168	1,130
North Carolina	-	-	131	261	108	18	169	-	-	-	-	147	836	833
North Dakota	-	2	81	137	198	-	-	-	-	-	-	-	418	403
Ohio	4	81	866	1,323	726	352	96	49	-	36	-	-	3,531	3,333
Oklahoma	1	335	789	1,275	681	432	-	1	-	-	-	177	3,691	3,288
Oregon	-	3	61	619	-	-	6	-	-	-	-	-	689	682
Pennsylvania	31	112	1,392	1,236	385	185	290	146	116	77	-	155	4,013	4,027
Rhode Island	3	-	14	-	-	-	-	-	-	-	-	-	17	17
South Carolina	-	-	9	360	106	10	102	-	-	-	-	178	635	567
South Dakota	-	-	564	54	-	22	-	-	-	-	-	-	640	575
Tennessee	-	-	-	267	118	-	-	-	-	-	-	-	385	365
Texas	373	1,280	3,770	3,678	1,966	1,376	305	68	34	92	-	110	13,054	10,608
Utah	-	1	11	292	7	2	-	-	-	-	-	-	313	488
Virginia	-	-	34	155	13	109	208	54	-	-	9	220	822	807
Washington	2	1	217	264	14	22	141	121	-	-	-	-	762	608
West Virginia	-	-	7	1	-	-	-	-	-	-	-	-	8	7
Wisconsin	-	-	72	172	109	41	-	72	-	-	-	-	466	464
Wyoming	23	1	327	464	170	-	-	-	-	-	-	-	1,185	1,009
Total January 1, 1971	702	2,771	16,732	25,636	9,765	8,732	2,441	1,603	919	907	9	2,171	72,406	-
Total January 1, 1968	641	2,619	16,002	22,833	8,187	7,189	2,129	1,441	937	1,075	9	1,678	-	66,529

1/ Includes a small amount of 5-inch pipe.
2/ Includes a small amount of 7-inch pipe.

BEGIN LAST LINE OF TEXT

TYPING GUIDE SHEET

Mileage of product pipelines in the United States, as of January 1, 1974

(Miles)

State	Size (inches) 2	3	4 1/	6 2/	8	10	12	14	16	18	20	22	24 (and over)	Total Jan. 1, 1974	Total Jan. 1, 1971
Alabama	-	-	13	36	85	43	402	-	2	310	-	-	567	1,462	1,163
Alaska	-	-	-	8	2	3	2	-	3	-	1	-	-	19	8
Arizona	-	-	-	173	262	-	292	-	-	200	-	-	-	967	896
Arkansas	-	-	36	38	36	403	268	-	1	-	297	-	-	1,077	901
California	32	91	322	641	962	392	323	263	66	-	-	-	16	3,108	r/ 2,831
Colorado	-	236	-	516	87	-	-	-	-	-	-	-	-	839	498
Connecticut	-	-	-	22	-	6	64	-	-	-	-	-	-	92	92
Delaware	-	-	-	-	-	-	-	-	-	-	-	-	6	6	3
Florida	-	-	-	112	-	120	-	-	-	-	-	-	-	232	87
Georgia	-	-	12	197	712	320	116	168	4	12	-	-	365	1,906	1,720
Idaho	-	-	-	-	554	79	-	-	-	-	-	-	-	633	640
Illinois	1	-	7	265	1,380	610	938	613	181	3	108	-	233	4,339	3,444
Indiana	2	4	10	98	1,179	457	333	328	165	-	195	-	-	2,771	2,378
Iowa	-	-	2	1,323	1,495	311	673	-	88	-	-	-	-	3,892	3,867
Kansas	1	-	152	1,277	2,641	984	276	-	246	-	-	-	-	5,577	5,976
Kentucky	-	-	60	47	-	1	-	-	-	-	-	-	-	108	50
Louisiana	-	6	274	564	549	507	314	-	191	110	66	-	225	2,806	2,759
Maine	-	-	-	125	-	-	-	-	-	-	-	-	-	125	126
Maryland and District of Columbia	-	-	-	60	26	-	36	-	-	-	-	-	98	220	219
Massachusetts	-	-	39	271	13	-	24	-	-	-	-	-	-	347	242
Michigan	-	1	-	294	488	290	166	-	251	-	-	-	-	1,490	1,410
Minnesota	-	-	14	357	906	137	291	-	-	-	-	-	-	1,705	1,772
Mississippi	-	-	-	-	99	-	522	-	76	222	106	-	455	1,579	1,123
Missouri	-	11	3	108	1,393	1,137	412	1	62	-	70	-	296	3,711	3,118
Montana	-	2	4	82	87	443	-	-	-	-	-	-	-	618	1,023
Nebraska	-	-	17	1,029	1,098	38	131	-	-	-	-	-	-	2,293	2,313
Nevada	-	-	8	2	161	1	2	44	-	-	-	-	-	198	328
New Jersey	1	-	-	136	39	13	37	79	54	2	-	-	92	453	569
New Mexico	-	40	107	672	364	-	-	-	-	-	-	-	-	1,183	1,205
New York	-	1	17	384	392	187	71	86	12	-	-	-	-	1,148	1,168
North Carolina	-	-	14	130	257	108	18	169	-	-	-	-	104	800	836
North Dakota	-	-	2	83	194	198	-	-	-	-	-	-	-	477	618
Ohio	2	3	82	789	1,449	728	346	94	54	-	34	-	-	3,581	3,331
Oklahoma	1	-	232	860	1,715	409	503	-	33	-	-	-	282	4,035	3,491
Oregon	-	-	2	61	592	-	1	17	-	-	-	-	-	673	689
Pennsylvania	40	4	71	1,362	1,230	283	188	289	144	114	77	-	155	3,969	4,013
Rhode Island	-	3	-	14	-	-	-	-	-	-	-	-	-	17	17
South Carolina	-	-	-	9	241	106	10	102	-	-	-	-	203	669	635
South Dakota	-	-	-	529	91	-	22	-	-	-	-	-	-	642	640
Tennessee	-	-	-	-	248	195	-	-	-	-	-	-	-	443	365
Texas	54	379	1,328	3,615	3,988	1,968	1,376	385	68	34	92	-	401	13,188	13,036
Utah	-	7	7	32	86	431	2	-	39	-	1	-	-	605	313
Virginia	-	-	-	65	155	13	109	209	54	-	-	9	220	834	822
Washington	-	2	1	161	174	14	24	161	129	-	30	-	-	696	762
West Virginia	-	1	39	8	2	-	-	-	-	-	-	-	-	50	8
Wisconsin	-	-	-	72	172	109	41	-	72	-	-	-	-	466	444
Wyoming	22	-	-	339	681	170	-	-	-	-	-	-	-	1,212	1,103
Total January 1, 1974	136	491	2,875	16,960	26,222	11,026	8,357	2,786	1,993	1,177	1,073	9	3,896	76,819	-
Total January 1, 1971	r/ 167	330	2,771	16,732	25,634	r/ 9,792	8,732	2,441	1,603	919	907	9	2,171	-	r/ 72,396

r/ Revised.
1/ Includes a small amount of 5-inch pipe.
2/ Includes a small amount of 7-inch pipe.

BEGIN FIRST LINE OF TEXT HERE
CENTER OF PAGE
TOP OF IMAGE AREA

Mileage of product pipelines in the United States, as of January 1, 1977

(Miles)

State	Size (inches)													Total	
	2	3	4 1/	6 2/	8	10	12	14	16	18	20	22	24 (and over)	Jan. 1, 1977	Jan. 1, 1974
Alabama	-	-	5	36	85	30	402	-	2	310	-	-	593	1,463	1,462
Alaska	-	-	-	8	2	74	2	-	3	-	1	-	-	90	19
Arizona	-	-	-	173	242	-	292	-	-	260	-	-	-	967	967
Arkansas	-	-	34	38	56	403	248	18	1	-	297	-	-	1,095	1,077
California	12	44	305	403	945	470	323	263	78	-	-	-	16	2,859	2,908
Colorado	-	272	-	447	87	162	-	-	-	-	-	-	-	968	839
Connecticut	-	-	-	22	1	7	64	-	-	-	-	-	-	94	92
Delaware	-	-	-	-	-	-	-	-	-	-	-	-	3	3	6
Florida	-	-	-	112	-	123	-	-	-	-	-	-	-	235	232
Georgia	-	-	12	197	712	320	254	148	4	12	-	-	365	2,024	1,886
Idaho	-	-	-	-	554	79	-	-	-	-	-	-	-	633	633
Illinois	1	-	6	277	1,370	646	667	370	200	39	108	-	233	3,917	4,159
Indiana	2	-	60	396	746	617	236	110	302	13	195	-	19	2,696	2,671
Iowa	-	-	22	1,358	1,643	314	823	295	84	-	-	-	-	4,539	3,892
Kansas	8	-	153	1,692	2,831	1,306	715	-	249	-	-	-	-	6,754	r/ 6,013
Kentucky	-	-	39	48	10	1	-	-	1	-	-	-	-	99	108
Louisiana	-	-	267	516	571	483	315	-	111	110	44	-	405	2,822	2,804
Maine	-	-	-	125	-	-	-	-	-	-	-	-	-	125	125
Maryland and District of Columbia	-	-	-	60	24	-	37	-	-	-	-	-	98	219	220
Massachusetts	-	-	28	178	8	-	24	-	-	-	4	-	-	242	272
Michigan	1	-	-	407	458	167	229	-	246	-	-	-	-	1,508	1,490
Minnesota	-	-	14	357	677	108	291	-	-	-	-	-	-	1,447	r/ 1,475
Mississippi	-	-	-	6	-	-	522	-	77	332	104	-	455	1,496	1,579
Missouri	-	11	-	116	1,458	1,526	289	1	62	-	70	-	294	3,827	3,711
Montana	-	2	4	82	399	443	-	-	-	-	-	-	-	930	618
Nebraska	-	-	17	1,064	1,059	38	152	-	-	-	-	-	-	2,330	2,293
Nevada	-	-	8	80	141	-	2	44	-	-	-	-	-	275	198
New Jersey	1	-	1	119	41	13	37	79	54	2	51	-	96	494	453
New Mexico	-	40	107	594	794	163	-	-	-	-	-	-	-	1,698	1,183
New York	1	1	17	366	380	187	69	84	12	-	-	-	-	1,117	1,148
North Carolina	-	-	14	145	257	108	19	169	-	-	-	-	184	896	900
North Dakota	-	-	-	82	194	220	-	-	-	-	-	-	-	496	477
Ohio	2	2	41	819	1,377	705	609	94	55	-	34	-	-	3,738	3,581
Oklahoma	2	-	321	788	1,884	516	801	1	60	-	-	-	333	4,706	r/ 4,250
Oregon	-	-	2	61	345	-	-	6	-	-	-	-	-	414	673
Pennsylvania	41	7	63	1,326	1,225	329	213	288	148	116	103	-	155	4,012	3,949
Rhode Island	-	3	-	14	-	-	-	-	-	-	-	-	-	17	17
South Carolina	-	-	-	9	240	104	10	102	-	-	-	-	203	668	669
South Dakota	-	-	-	529	91	-	22	-	-	-	-	-	-	642	642
Tennessee	-	-	-	-	248	195	32	-	-	-	-	-	-	475	443
Texas	54	245	1,279	3,648	4,441	1,789	1,521	395	76	10	151	-	521	14,130	r/ 14,026
Utah	-	-	2	9	288	5	2	-	-	-	-	-	-	306	r/ 312
Virginia	-	-	-	55	155	13	109	209	54	-	-	9	220	824	834
Washington	-	2	1	156	174	14	23	141	126	-	76	-	-	713	696
West Virginia	-	1	60	249	116	-	-	-	-	-	-	-	-	426	358
Wisconsin	-	-	-	71	172	109	40	-	72	-	-	-	-	464	466
Wyoming	-	-	13	527	692	171	-	-	-	-	-	-	-	1,403	1,212
Total January 1, 1977	125	630	2,895	17,565	27,193	11,958	9,394	2,817	2,077	1,202	1,238	9	4,193	81,296	-
Total January 1, 1974	156	r/ 688	r/ 2,870	r/ 16,786	r/ 27,329	r/ 10,612	r/ 8,703	2,786	r/ 1,954	1,177	r/ 1,072	9	3,896	-	r/ 78,038

r/ Revised.
1/ Includes a small amount of 5-inch pipe.
2/ Includes a small amount of 7-inch pipe.

TYPING GUIDE SHEET

Mileage of crude trunklines in the United States as of January 1, 1971

(Miles)

State	Size (inches)																
	Under 4	4 1/	6 1/	8 2/	10	12	14	16	18	20	22	24	26	28	30 and over)	Total	
																Jan. 1, 1971	Jan. 1, 1968
Alabama	-	-	-	30	-	-	26	-	-	-	-	-	-	-	-	56	56
Alaska	-	1	-	21	4	2	-	-	-	45	-	-	-	-	6	79	76
Arizona	-	-	-	9	-	21	-	347	-	-	-	-	-	-	-	377	368
Arkansas	-	5	178	155	9	6	-	-	-	298	-	-	-	-	-	651	657
California	10	31	461	1,713	660	527	153	508	182	200	-	4	-	-	4	4,453	4,411
Colorado	-	52	260	93	262	67	-	12	81	30	65	-	-	-	-	906	691
Illinois	9	115	236	262	906	967	41	63	238	423	395	15	206	-	227	4,079	3,886
Indiana	1	21	127	165	320	207	16	10	16	205	181	2	-	-	65	1,336	1,256
Iowa	-	-	-	-	-	25	-	1	-	16	-	-	-	-	-	42	66
Kansas	-	106	625	836	661	595	-	14	227	401	128	369	-	-	-	3,937	3,962
Kentucky	-	20	11	1	-	-	-	-	-	6	226	-	3	-	51	316	272
Louisiana	18	281	429	498	117	531	16	422	66	577	360	-	-	-	74	3,367	3,011
Maine	-	-	-	-	-	73	-	-	72	-	-	76	-	-	8	229	219
Michigan	1	197	319	331	1	1	-	161	-	16	7	-	-	-	768	1,802	1,499
Minnesota	-	-	-	-	-	-	-	333	283	-	-	-	283	-	282	1,183	1,150
Mississippi	3	90	97	243	355	13	64	1	-	4	188	-	-	-	289	1,347	966
Missouri	1	-	-	8	817	1,149	-	38	-	649	381	136	-	-	-	3,177	3,413
Montana	12	95	66	367	167	460	-	100	-	-	-	-	-	-	-	1,267	958
Nebraska	-	4	27	56	8	38	-	-	-	452	57	-	-	-	-	640	617
New Hampshire	-	-	-	-	-	38	-	-	35	-	1	36	-	-	-	108	109
New Mexico	1	26	57	562	127	86	94	489	-	5	-	-	-	-	-	1,443	1,479
New York	50	17	-	-	-	26	-	-	-	-	-	-	-	-	-	93	188
North Dakota	-	-	75	6	99	171	-	406	28	-	-	-	28	-	28	839	763
Ohio	10	26	180	573	85	311	2	16	1	181	131	1	-	-	-	1,515	1,981
Oklahoma	16	216	789	2,680	1,102	586	2	581	46	80	143	248	3	-	-	6,486	6,498
Pennsylvania	132	172	891	122	11	-	-	8	-	-	-	-	-	-	6	1,362	1,497
Tennessee	-	-	-	-	-	-	-	-	-	-	154	-	-	-	110	264	134
Texas	150	1,526	3,438	8,981	3,382	3,322	99	1,660	659	1,163	274	562	503	-	2	28,119	26,006
Utah	7	7	32	82	434	2	-	39	-	1	-	-	-	-	-	604	586
Vermont	-	-	-	-	-	59	-	-	59	-	-	59	-	-	-	177	177
Washington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	64
West Virginia	-	1	418	12	-	-	-	-	-	-	-	-	-	-	-	431	432
Wisconsin	-	-	-	-	-	-	-	-	13	-	-	-	13	-	450	476	130
Wyoming	40	89	719	1,483	182	627	62	421	-	288	-	-	-	-	-	3,911	3,235
January 1, 1971	479	3,090	9,435	19,269	11,867	10,106	571	5,630	2,002	5,060	2,664	1,506	1,039	-	2,370	75,066	-
January 1, 1968	269	2,075	8,897	19,325	12,198	9,288	348	5,361	1,992	4,765	2,659	1,497	830	-	961	-	70,825

1/ Includes a small amount of 3-inch pipe.
2/ Includes a small amount of 7-inch pipe.
3/ Includes a small amount of 9-inch pipe.

TYPING GUIDE SHEET

Mileage of crude trunklines in the United States as of January 1, 1974

(Miles)

State	Size (inches)															Total	
	2	3	4 1/	6 2/	8 3/	10	12	14	16	18	20	22	24	26	30 (and over)	Jan. 1, 1974	Jan. 1, 1971
Alabama	-	-	-	37	32	-	102	26	37	-	-	-	-	-	-	232	54
Alaska	-	-	1	-	19	5	6	-	-	-	45	-	-	-	6	82	79
Arizona	-	-	-	-	9	-	21	-	347	-	-	-	-	-	-	377	377
Arkansas	2	6	28	371	123	19	11	-	-	-	298	-	-	-	-	858	651
California	7	16	72	388	2,253	494	482	186	521	191	200	1	2	-	4	4,815	4,453
Colorado	6	6	61	237	93	247	68	-	12	80	30	65	-	-	-	907	904
Florida	-	-	-	-	-	-	-	-	28	-	-	-	-	-	-	28	-
Illinois	1	8	226	234	294	904	957	41	63	236	300	341	17	206	251	4,279	r/ 4,156
Indiana	-	-	22	127	168	310	206	14	10	16	205	181	2	-	61	1,322	1,334
Iowa	-	-	-	-	-	-	25	-	1	-	16	17	-	-	-	59	42
Kansas	6	27	94	637	1,017	578	631	-	13	227	401	123	369	-	-	4,123	3,937
Kentucky	-	-	42	11	1	-	-	-	-	-	6	224	-	3	51	338	316
Louisiana	2	17	303	654	491	121	574	16	398	145	566	378	-	-	77	3,740	3,367
Maine	-	-	-	-	-	-	73	-	-	72	-	-	76	-	8	229	229
Michigan	-	1	174	275	307	1	1	-	161	-	16	7	-	-	768	1,711	1,802
Minnesota	-	-	-	-	-	-	-	-	441	283	-	-	-	282	388	1,394	1,183
Mississippi	-	3	91	96	263	355	16	64	1	-	4	188	-	-	290	1,351	1,347
Missouri	1	-	-	-	8	858	1,148	-	38	-	649	381	134	-	-	3,217	3,177
Montana	-	31	95	93	381	176	451	-	100	-	-	-	-	-	-	1,327	1,267
Nebraska	-	-	4	27	54	8	38	-	-	-	452	57	-	-	-	640	640
New Hampshire	-	-	-	-	-	38	-	-	-	35	-	1	34	-	-	108	108
New Mexico	1	-	26	93	339	127	86	94	489	-	5	-	-	-	-	1,456	1,443
New York	25	7	11	-	163	-	91	-	-	-	4	-	-	-	-	301	93
North Dakota	-	-	-	74	14	99	111	-	406	28	-	-	-	28	28	786	839
Ohio	2	8	26	180	613	84	284	2	17	1	182	131	-	-	1	1,529	1,515
Oklahoma	7	8	225	780	2,618	1,002	621	-	568	46	81	163	248	3	-	6,350	6,486
Pennsylvania	27	130	172	713	122	2	23	-	8	-	1	-	-	-	6	1,204	1,362
Tennessee	-	-	-	-	-	-	-	-	-	-	-	154	-	-	110	264	264
Texas	12	205	1,584	3,414	9,237	4,985	3,472	95	1,533	659	978	272	542	499	3	27,490	28,119
Utah	-	7	7	32	86	431	2	-	39	-	1	-	-	-	-	605	604
Vermont	-	-	-	-	-	-	59	-	-	59	-	-	59	-	-	177	177
Washington	-	-	-	-	-	-	-	-	20	-	44	-	-	-	-	64	-
West Virginia	-	-	6	445	-	-	-	-	-	-	-	-	-	-	-	451	431
Wisconsin	-	-	-	-	-	-	-	-	-	13	-	-	-	13	450	476	476
Wyoming	1	1	78	750	1,537	196	626	62	421	-	288	-	-	-	-	3,960	3,911
Total Jan. 1, 1974.	100	479	3,344	9,668	20,424	11,[illegible]40	10,183	598	5,668	2,091	4;972	2,664	1,483	1,034	2,502	76,250	-
Total Jan. 1, 1971.	4/	479	r/ 3,201	r/ 9,410	r/ 19,221	11,867	r/ 10,096	571	5,630	2,002	r/ 5,117	r/ 2,610	r/ 1,506	1,039	r/ 2,394	-	r/ 75,143

r/ Revised.
1/ Includes a small amount of 5-inch pipe.
2/ Includes a small amount of 7-inch pipe.
3/ Includes a small amount of 9-inch pipe.
4/ Prior to 1974 data for 2-inch pipe included with 3-inch pipe.

BEGIN FIRST LINE OF TEXT HERE
CENTER OF PAGE
TOP OF IMAGE AREA
DROPPED HEAD BEGIN SECTIONS HERE

Mileage of crude trunklines in the United States as of January 1, 1977

(Miles)

State	Size (inches)															Total	
	2	3	4 1/	6 2/	8 3/	10	12	14	16	18	20	22	24	26	30 (and over)	Jan. 1, 1977	Jan. 1, 1974
Alabama	-	-	-	37	22	26	-	24	37	-	-	-	-	-	11	157	232
Alaska	-	-	1	-	19	3	6	-	-	-	45	-	-	-	6	80	82
Arizona	-	-	-	-	20	-	21	-	347	-	-	-	-	-	-	388	377
Arkansas	-	6	47	382	123	19	11	-	-	-	298	-	-	-	-	886	838
California	13	15	53	387	2,122	545	543	186	526	191	188	14	15	-	4	4,802	4,815
Colorado	-	-	56	286	95	246	68	-	12	80	30	65	-	-	-	938	907
Florida	-	-	-	-	-	-	-	-	34	-	-	-	-	-	-	34	28
Illinois	2	7	206	228	261	809	928	41	63	236	445	341	18	264	232	4,099	4,279
Indiana	-	-	21	147	151	290	206	14	10	16	205	181	2	-	72	1,315	1,322
Iowa	-	-	-	-	-	-	25	-	1	-	16	-	-	-	-	42	59
Kansas	7	22	164	558	810	527	679	-	11	227	521	123	369	-	-	3,998	4,123
Kentucky	-	-	30	10	30	-	-	-	-	-	20	224	265	3	51	633	338
Louisiana	2	17	293	667	496	114	559	-	428	143	678	379	-	-	86	3,862	3,740
Maine	-	-	-	-	-	-	73	-	-	72	-	-	75	-	8	228	229
Michigan	2	3	192	293	605	71	11	2	184	1	9	98	-	-	825	2,296	1,711
Minnesota	-	-	-	-	-	-	-	-	441	283	-	-	-	282	388	1,394	1,394
Mississippi	-	3	91	93	236	346	13	64	1	-	4	188	-	-	390	1,329	1,351
Missouri	1	-	-	-	8	858	1,246	-	38	-	649	381	134	-	-	3,315	3,217
Montana	-	31	166	92	389	167	511	-	100	-	-	-	-	-	-	1,456	1,327
Nebraska	-	-	3	28	51	8	38	-	-	-	452	57	-	-	-	637	640
New Hampshire	-	-	-	-	-	68	8	4	-	55	-	1	54	-	-	190	108
New Mexico	1	1	25	93	526	127	84	94	489	-	-	207	-	-	-	1,647	1,456
New York	26	7	11	-	-	-	91	-	-	-	4	-	-	-	-	139	301
North Dakota	-	-	-	74	14	99	170	-	329	28	-	-	-	28	28	770	786
Ohio	-	-	19	132	491	61	262	2	12	-	180	116	-	-	-	1,275	1,529
Oklahoma	4	8	196	984	2,293	1,002	624	-	630	46	279	143	249	3	315	6,778	6,350
Pennsylvania	13	119	151	602	96	510	13	-	8	-	-	-	-	-	7	1,519	1,204
Tennessee	-	-	-	-	-	-	-	-	-	-	-	154	-	-	110	264	264
Texas	12	221	1,436	3,276	8,911	4,743	3,280	96	1,787	607	896	387	1,016	476	667	27,811	27,490
Utah	-	7	7	80	91	447	2	-	39	-	1	-	-	-	-	674	605
Vermont	-	-	-	-	-	-	59	-	-	59	-	-	59	-	-	177	177
Washington	-	-	-	-	-	-	-	-	27	-	43	-	-	-	-	70	64
West Virginia	-	-	6	396	-	-	-	-	-	-	-	-	-	-	-	602	451
Wisconsin	-	-	-	-	-	-	-	-	-	-	-	-	-	13	449	462	476
Wyoming	1	1	88	673	1,441	272	625	62	421	13	288	-	-	-	-	3,885	3,960
Total Jan. 1, 1977	84	468	3,260	9,318	19,303	11,358	10,136	389	5,975	2,059	5,251	3,059	2,256	1,069	3,367	77,972	-
Total Jan. 1, 1974	100	479	3,344	9,688	20,426	11,040	10,183	398	5,668	2,091	4,972	2,664	1,483	1,034	2,502	-	76,250

1/ Includes a small amount of 5-inch pipe.
2/ Includes a small amount of 7-inch pipe.
3/ Includes a small amount of 9-inch pipe.

BEGIN LAST LINE OF TEXT
BOTTOM OF IMAGE AREA OUTSIDE DIMENSION

PAGE NUMBER
EPA Form 2200-4 (4-80)
(PREVIOUSLY EPA FORM 327)
TYPING GUIDE SHEET

Pipeline fill for petroleum pipelines in the United States, January 1, 1974 and January 1, 1971

(Thousand barrels)

State	Gathering lines		Crude-oil trunklines		Total crude lines		Product lines	
	Jan. 1, 1974	Jan. 1, 1971	Jan. 1, 1974	Jan. 1, 1971	Jan. 1, 1974	Jan. 1, 1971	Jan. 1, 1974	Jan. 1, 1971
Alabama	10	7	161	33	171	40	4,246	r/ 4,231
Alaska	12	-	131	128	143	128	11	2
Arizona	1	-	446	446	447	446	727	321
Arkansas	76	60	699	662	775	722	885	897
California	509	543	2,970	2,516	3,479	3,059	1,379	r/ 1,109
Colorado	74	67	604	606	678	673	138	107
Connecticut	-	-	-	-	-	-	55	55
Delaware	-	-	-	-	-	-	28	16
Florida	5	-	35	-	40	-	62	32
Georgia	-	-	-	-	-	-	2,623	2,260
Idaho	-	-	-	-	-	-	328	60
Illinois	216	262	5,955	r/ 5,917	6,171	r/ 6,179	3,089	1,948
Indiana	34	42	1,341	1,481	1,375	1,523	1,687	1,503
Iowa	-	-	89	50	89	50	1,519	1,369
Kansas	678	683	3,670	3,613	4,348	4,276	2,163	2,402
Kentucky	144	133	954	r/ 951	1,098	r/ 1,084	14	10
Louisiana	495	536	4,097	3,827	4,592	4,363	2,926	2,411
Maine	-	-	405	376	405	376	24	23
Maryland and District of Columbia	-	-	-	-	-	-	511	511
Massachusetts	-	-	-	-	-	-	76	52
Michigan	64	r/ 44	3,963	3,966	4,027	r/ 4,010	802	760
Minnesota	-	-	4,762	r/ 3,377	4,762	r/ 3,377	215	401
Mississippi	52	66	3,120	3,112	3,172	3,178	2,387	1,119
Missouri	-	-	3,827	3,806	3,827	3,806	2,486	1,310
Montana	98	85	703	571	801	656	228	450
Nebraska	60	68	1,047	1,047	1,107	1,115	112	664
Nevada	-	-	-	-	-	-	92	97
New Hampshire	-	-	208	178	208	178	-	-
New Jersey	5	5	-	-	5	5	639	746
New Mexico	373	410	1,029	1,030	1,402	1,440	231	415
New York	13	12	132	22	145	34	449	401
North Carolina	-	-	-	-	-	-	1,383	1,109
North Dakota	48	34	943	983	991	1,017	183	122
Ohio	93	96	1,175	1,177	1,268	1,271	1,496	1,463
Oklahoma	1,116	1,114	3,981	4,032	5,097	5,146	2,039	1,867
Oregon	-	-	-	-	-	-	240	227
Pennsylvania	92	93	254	273	346	366	2,220	2,229
Rhode Island	-	-	-	-	-	-	3	3
South Carolina	-	-	-	-	-	-	833	1,133
South Dakota	-	-	-	-	-	-	147	144
Tennessee	-	-	680	1,235	680	1,235	184	166
Texas	3,129	r/ 2,878	17,764	18,599	20,893	r/ 21,477	6,878	5,436
Utah	28	28	309	310	337	338	309	106
Vermont	-	-	297	297	297	297	-	-
Virginia	-	-	-	-	-	-	1,535	1,337
Washington	-	-	108	-	108	-	500	309
West Virginia	120	129	84	83	204	212	3	2
Wisconsin	-	-	2,460	2,460	2,460	2,460	347	267
Wyoming	278	r/ 261	2,336	2,328	2,634	r/ 2,589	383	295
Total	7,823	r/ 7,636	71,159	r/ 69,492	78,982	r/ 77,126	48,775	r/ 42,272

r/ Revised.

Pipeline fill for petroleum pipelines in the United States, January 1, 1977 and January 1, 1974

(Thousand barrels)

State	Gathering lines		Crude-oil trunklines		Total crude lines		Product lines	
	Jan. 1, 1977	Jan. 1, 1974	Jan. 1, 1977	Jan. 1, 1974	Jan. 1, 1977	Jan. 1, 1974	Jan. 1, 1977	Jan. 1, 1974
Alabama	6	10	169	161	175	171	4,358	4,246
Alaska	8	12	130	131	138	143	47	11
Arizona	-	1	450	446	450	447	727	727
Arkansas	70	76	702	699	772	775	1,002	985
California	499	509	3,068	2,970	3,567	3,479	1,291	1,379
Colorado	82	74	612	604	694	678	184	138
Connecticut	-	-	-	-	-	-	52	55
Delaware	-	-	-	-	-	-	14	28
Florida	6	5	42	35	48	40	84	62
Georgia	-	-	-	-	-	-	2,725	2,623
Idaho	-	-	-	-	-	-	228	228
Illinois	223	216	5,830	5,955	6,053	6,171	2,845	3,089
Indiana	31	34	1,579	1,541	1,610	1,575	1,743	1,687
Iowa	-	-	50	89	50	89	1,963	1,519
Kansas	818	678	3,824	3,670	4,642	4,348	2,760	r/ 2,484
Kentucky	117	144	1,725	954	1,842	1,098	17	14
Louisiana	751	495	4,386	4,097	5,137	4,592	4,089	2,924
Maine	-	-	421	405	421	405	24	24
Maryland and District of Columbia	-	-	-	-	-	-	510	511
Massachusetts	-	-	-	-	-	-	64	76
Michigan	156	64	4,604	3,963	4,760	4,027	790	802
Minnesota	-	-	4,662	4,762	4,662	4,762	368	r/ 583
Mississippi	56	52	3,111	3,120	3,167	3,172	4,016	2,387
Missouri	-	-	3,899	3,827	3,899	3,827	2,541	2,486
Montana	107	98	751	703	858	801	257	228
Nebraska	60	60	1,046	1,047	1,106	1,107	693	112
Nevada	-	-	-	-	-	-	106	92
New Hampshire	-	-	280	208	280	208	-	-
New Jersey	-	r/	-	-	-	r/	745	639
New Mexico	421	373	1,495	1,029	1,916	1,402	476	291
New York	8	13	77	132	85	145	440	449
North Carolina	-	-	-	-	-	-	1,383	1,383
North Dakota	52	48	894	943	946	991	194	183
Ohio	116	93	1,043	1,175	1,159	1,268	1,657	1,496
Oklahoma	1,042	1,116	4,356	3,981	5,398	5,097	2,932	r/ 2,548
Oregon	-	-	-	-	-	-	134	260
Pennsylvania	78	92	479	254	557	346	2,304	2,220
Rhode Island	-	-	-	-	-	-	3	3
South Carolina	-	-	-	-	-	-	593	833
South Dakota	-	-	-	-	-	-	167	167
Tennessee	-	-	1,235	880	1,235	880	208	184
Texas	2,969	3,129	21,995	17,764	24,964	20,893	7,616	r/ 7,162
Utah	23	28	328	309	351	337	103	r/ 106
Vermont	-	-	297	297	297	297	-	-
Virginia	-	-	-	-	-	-	1,533	1,535
Washington	-	-	115	108	115	108	544	500
West Virginia	99	120	75	84	174	204	91	72
Wisconsin	-	-	2,434	2,460	2,434	2,460	244	247
Wyoming	295	278	2,368	2,356	2,663	2,634	423	383
Total	8,091	r/ 7,818	78,514	71,159	86,605	78,977	55,468	r/ 50,121

r/ Revised.

Pipeline fill for petroleum pipelines in the United States, January 1, 1971 and January 1, 1968

(Thousand barrels)

State	Gathering lines		Crude-oil trunklines		Total crude lines		Product lines	
	Jan. 1, 1971	Jan. 1, 1968	Jan. 1, 1971	Jan. 1, 1968	Jan. 1, 1971	Jan. 1, 1968	Jan. 1, 1971	Jan. 1, 1968
Alabama	7	1	33	33	40	34	2,158	2,120
Alaska	-	-	128	122	128	122	2	-
Arizona	-	-	446	443	446	443	321	322
Arkansas	60	56	662	661	722	717	897	897
California	543	687	2,516	2,757	3,059	3,444	818	834
Colorado	67	103	606	569	673	672	107	108
Connecticut	-	-	-	-	-	-	55	56
Delaware	-	-	-	-	-	-	16	14
Florida	-	-	-	-	-	-	32	18
Georgia	-	-	-	-	-	-	2,260	1,655
Idaho	-	-	-	-	-	-	60	227
Illinois	262	285	4,510	3,461	4,772	3,746	1,966	1,898
Indiana	42	55	1,481	1,160	1,523	1,215	1,503	1,333
Iowa	-	-	50	61	50	61	1,549	1,179
Kansas	663	763	3,613	3,592	4,276	4,355	2,402	1,772
Kentucky	133	133	585	545	718	678	10	10
Louisiana	536	525	3,827	2,869	4,363	3,394	2,411	2,590
Maine	-	-	376	371	376	371	23	61
Maryland and District of Columbia	-	-	-	-	-	-	511	513
Massachusetts	-	-	-	-	-	-	52	52
Michigan	436	100	3,966	2,983	4,402	3,083	760	689
Minnesota	-	-	2,396	3,198	2,396	3,198	401	669
Mississippi	66	62	3,112	823	3,178	885	1,119	r/1,006
Missouri	-	-	3,806	3,889	3,806	3,889	1,510	1,415
Montana	85	77	571	463	656	540	450	382
Nebraska	68	96	1,047	1,033	1,115	1,129	666	561
Nevada	-	-	-	-	-	-	97	98
New Hampshire	-	-	178	180	178	180	-	-
New Jersey	5	-	-	-	5	-	746	946
New Mexico	410	426	1,030	1,032	1,440	1,458	415	330
New York	12	17	22	62	34	79	401	430
North Carolina	-	-	-	-	-	-	1,109	1,250
North Dakota	34	52	983	893	1,017	945	122	176
Ohio	94	96	1,177	1,330	1,271	1,426	1,465	1,238
Oklahoma	1,114	1,419	4,032	4,040	5,146	5,459	1,867	1,147
Oregon	-	-	-	-	-	-	227	130
Pennsylvania	93	112	273	330	366	442	2,229	2,201
Rhode Island	-	-	-	-	-	-	3	3
South Carolina	-	-	-	-	-	-	1,153	911
South Dakota	-	-	-	-	-	-	144	129
Tennessee	-	-	1,235	357	1,235	357	144	144
Texas	1,300	2,744	18,599	17,964	19,899	20,708	5,434	4,319
Utah	28	68	310	300	338	368	106	422
Vermont	-	-	297	297	297	297	-	-
Virginia	-	-	-	-	-	-	1,357	1,328
Washington	-	-	-	108	-	108	309	388
West Virginia	129	134	83	83	212	217	2	1
Wisconsin	-	-	2,460	557	2,460	557	247	246
Wyoming	717	296	2,328	2,039	3,045	2,335	296	289
Total	6,906	8,305	66,738	58,605	73,642	66,910	39,908	r/36,701

r/ Revised.

APPENDIX C

SUMMARY OF LIQUID PIPELINE ACCIDENT REPORTS ON DOT FORM 1000-1 COMPILED BY THE OFFICE OF PIPELINE SAFETY FOR YEARS 1969-1976

LIQUID PIPELINE ACCIDENT SUMMARY - JANUARY 1, 1969, THROUGH DECEMBER 31, 1969

CAUSE OF ACCIDENT	NO. OF ACCIDENTS	% OF TOTAL	DEATHS		INJURIES		PROPERTY DAMAGE ($)			LOSS OF COMMODITY (BARRELS)	NO. OF ACCIDENTS BY YEAR OF INSTALLATION						
			CARRIER EMPLOYEES	NON EMPLOYEES	CARRIER EMPLOYEES	NON EMPLOYEES	CARRIER	OTHER	TOTAL		Before 1920	1920-1929	1930-1939	1940-1949	1950-1959	1960-1969	Not Reported
Operation Accidents																	
Corrosion - External	134	33.3				1	12,977	40,185	53,162	70,478(9)	29	20	31	26	19	7	2
Equipment Rupturing Line	90	22.3	1	1			66,661(1)	170,193(7)	236,857	85,400	7	10	11	18	26	17	1
Defective Pipe Seam	31	7.7					4,836	13,630	18,506	48,063	1	5	6	6	1	11	1
Corrosion - Internal	17	4.2					1,011	913	1,924	5,773	-	3	3	6	3	-	-
Incorrect Operation by Carrier Personnel	13	3.2	1	1			861,890(3)	6,470	868,360	14,287	1	2	-	2	2	3	1
Rupture of Previously Damaged Pipe	12	3.0					14,233	12,173	26,358	9,881	1	-	-	1	6	4	-
Ruptured, Leaking, or Malfunction of Valve	11	2.7					12,340	435	12,775	2,168	1	-	-	2	1	6	1
Malfunction of Control or Relief Equipment	5	1.2					3,333	850	4,283	11,483	-	-	-	-	2	3	-
Ruptured Gasket	5	1.2					[illegible]	[illegible]	481	1,263	-	-	1	1	-	3	-
Unknown	4	1.0					8,500	18,833	28,353	2,875	-	1	-	-	3	-	-
Mechanical Seal Failure	4	1.0					63,500(4)	123	63,623	971	-	-	1	-	3	-	-
Defective Pipe - Base Metal	4	1.0					110	3,000	3,110	1,744	-	1	-	-	1	1	1
Defective Girth Weld (Arc)	3	0.7					700	100	800	18,932(10)	-	-	-	-	-	3	-
Flood	3	0.7					440	-0-	440	4,110	-	-	-	1	1	1	-
Stress Crack (Pipe Settled on Rock)	3	0.7					12,003(14)	1,000	13,003	2,098	-	1	-	-	-	2	-
Leak Clamp Gasket Failure	3	0.7					-0-	5,000(5)	5,000	1,383	-	-	1	1	-	1	-
Failure of Welded Repair Sleeve or Half-Sole	3	0.7					400	1,350	1,750	1,250	-	1	1	-	1	-	-
Defective Girth Weld (Acetylene)	2	0.5					425	-0-	425	7,891(11)	-	1	1	-	-	-	-
Landslide	2	0.5					2,000	-0-	2,000	1,425	-	-	-	1	1	-	-
Surge	2	0.5					1,300	25,250(6)	26,550	8,430(12)	1	-	-	-	1	-	-
Pump Packing Failure	2	0.5					-0-	100	100	1,500	-	1	-	-	1	-	-
Miscellaneous	29	7.2			1	1	188,728(2)	236,840(8)	425,568	21,350(13)	2	4	3	3	6	9	2
TOTALS - Accidents During Operations	403	100.0	3	2	1	3	$1,265,137	$530,623	$1,795,760	$343,491	54	61	60	68	79	73	8
Test Accidents																	
Pipe Lamination	4	57.1					685	280	965	330	-	-	-	-	-	-	4
External Corrosion	2	28.6					-0-	500	500	131	-	-	1	-	1	-	-
Pipe Plate Flaw	1	14.3					723	150	873	184	-	-	-	-	-	1	-
TOTALS - Accidents During Tests	7	100.0	0	0	0	0	$ 1,408	$ 930	$ 2,338	645	-	-	1	-	1	1	4

(1) Includes one accident with $30,000 property damage.
(2) Includes accidents with property damages of $27,000, $45,000, $20,000 and $30,000.
(3) Includes accidents with property damages of $750,000, $90,000 and $20,000.
(4) Includes one accident with $58,000 property damage.
(5) Includes one accident with property damage of $7,500.
(6) Includes one accident with $25,000 property damage.
(7) Includes accidents with property damages of $20,000, $40,000 and $100,000.
(8) Includes one accident with property damage of $225,000.
(9) Includes one accident with loss of 17,190 barrels.
(10) Includes one accident with loss of 8,982 barrels.
(11) Includes one accident with loss of 7,641 barrels.
(12) Includes one accident with loss of 7,700 barrels.
(13) Includes one accident with loss of 8,330 barrels.
(14) Includes one accident with $12,000 property damage.

Department of Transportation
Pipeline accidents from DOT Form 7000-1
January 1, 1969, through December 31, 1969
Compiled by the Office of Pipeline Safety
February 13, 1970

SUMMARY - BY COMMODITY INVOLVED

COMMODITY	NO. OF ACCIDENTS	% OF TOTAL	LOSS (BARRELS)	% OF TOTAL	PROPERTY DAMAGE ($)				DEATHS		INJURIES	
					CARRIER	OTHERS	TOTAL	% OF TOTAL	CARRIER EMPLOYEES	NON EMPLOYEES	CARRIER EMPLOYEES	NON EMPLOYEES
OPERATIONS ACCIDENTS												
Crude Oil	246	61	176,640(1)	51	831,530(4)	344,730(7)	1,176,260	66				
Gasoline	62	15	50,346	15	66,861	43,424	110,285	6	1			
LPG	48	12	79,146(2)	23	157,569(5)	58,484(8)	216,053	12	2	2	1	3
Fuel Oil	23	6	22,206(3)	6	107,720(6)	75,500(9)	183,220	10				
Diesel Fuel	8	2	5,479	2	1,129	4,900	6,029	(*)				
Jet Fuel	6	1	3,169	1	17	675	692	(*)				
Alkylate	3	1	1,310	(*)	35	310	345	(*)				
Anhydrous Ammonia	2	(*)	1,959	(*)	100	2,115	2,215	(*)				
Condensate	2	(*)	6,602	1	176	400	576	(*)				
Kerosine	1	(*)	100	(*)	-0-	10	10	(*)				
Natural Gasoline	1	(*)	516	(*)	100,000	75	100,075	6				
Trans Mix	1	(*)	222	(*)	-0-	-0-	-0-	-0-				
TOTALS - DURING OPERATIONS	403	100	343,691	100	$1,265,137	$530,623	$1,795,760	100	3	2	1	3
TEST ACCIDENTS												
Crude Oil	6	86	565	85	685	780	1,465	63				
Fuel Oil	1	14	100	15	723	150	873	37				
TOTALS - DURING TESTS	7	100	665	100	$ 1,408	$ 930	$ 2,338	100	0	0	0	0

(*) Less than 1.0 percent.

(1) Includes 5 accidents where loss was 5,000 barrels or over.
(2) Includes accidents with losses of 8982, 7641, 7227, and 6750 barrels.
(3) Includes one accident of 6709 barrels.
(4) Includes one accident with damage of $750,000.
(5) Includes one accident with damage of $90,000.
(6) Includes one with $58,000 and one with $30,000 damage.
(7) Includes accidents with damages of $225,000, $25,000 and $19,853.
(8) Includes accidents with damages of $27,000 and $20,000.
(9) Includes one with damage of $65,000.

DEPARTMENT OF TRANSPORTATION
Pipeline accidents from DOT Form 7000-1
January 1, 1969, through December 31, 1969
Compiled by the Office of Pipeline Safety
February 13, 1970

SUMMARY - BY COMMODITY INVOLVED

COMMODITY	NO. OF ACCIDENTS	% OF TOTAL	LOSS (BARRELS)	% OF TOTAL	PROPERTY DAMAGE ($)				DEATHS		INJURIES	
					CARRIER	OTHERS	TOTAL	% OF TOTAL	CARRIER EMPLOYEES	NON EMPLOYEES	CARRIER EMPLOYEES	NON EMPLOYEES
OPERATIONS ACCIDENTS												
Crude Oil	216	62.2	383,160	73.4	333,719	79,987	413,756	46.0		1	1	
Gasoline	63	18.2	47,230	9.1	68,232	7,920	76,152	8.5	1			5
LPG	24	6.9	46,341	8.9	44,402	321,035	365,437	40.5		2	1	12
Fuel Oil	15	4.3	22,935	4.4	6,400	21,375	27,725	3.1				
Diesel Fuel	10	2.9	10,202	2.0	3,729	2,775	6,504	0.7				
Jet Fuel	9	2.6	6,116	1.2	1,339	470	1,809	0.2				
Anhydrous Ammonia	4	1.2	1,025	.2	25	800	825	.1			2	
Kerosine	2	.6	1,934	.3	1,750	700	2,450	.3				
Natural Gasoline	3	.8	2,806	.5	3,400	1,150	4,550	.6				
Propylene	1	.3	100	.0	20	0	20	.0				
TOTALS - DURING OPERATIONS	347	100.0	521,849	100.0	463,016	436,212	899,228	100.0	1	3	4	17

Department of Transportation
Pipeline accidents from DOT Form 7000-1
January 1, 1970, through December 31, 1970
Compiled by the Office of Pipeline Safety
April 1, 1971

LIQUID PIPELINE ACCIDENT SUMMARY - January 1, 1970, THROUGH DECEMBER 31, 1970

CAUSE OF ACCIDENT	NO. OF ACCIDENTS	% OF TOTAL	DEATHS		INJURIES		PROPERTY DAMAGE ($)			LOSS OF COMMODITY (BARRELS)	NO. OF ACCIDENTS BY YEAR OF INSTALLATION						
			CARRIER EMPLOYEES	NON EMPLOYEES	CARRIER EMPLOYEES	NON EMPLOYEES	CARRIER	OTHER	TOTAL		Before 1920	1920-1929	1930-1939	1940-1949	1950-1959	1960-1969	Not Reported
Operation Accidents																	
Corrosion - External	149	42.9	-	-	1	4	27,329	41,092	68,421	43,232	36	34	30	26	13	9	1
Equipment Rupturing Line	70	20.2	-	1	2	1	61,525	58,375	119,900	80,121	4	8	10	11	26	11	0
Defective Pipe Seam	29	8.4	-	-	-	-	2,865	9,635	12,500	40,176	1	6	6	3	9	4	0
Corrosion - Internal	30	8.7	-	-	-	10	137,000	206,380	343,380	15,616	1	1	1	3	16	8	0
Incorrect Operation by Carrier Personnel	13	3.8	-	2	-	-	4,663	11,673	16,336	26,806	1	-	-	7	1	3	1
Rupture of Previously Damaged Pipe	5	1.4	-	-	-	-	18,200	0	18,200	1,410	-	-	-	-	2	3	-
Ruptured, Leaking, or Malfunction of Valve	3	0.9	-	-	-	-	82	600	682	3,470	-	-	-	-	3	-	-
Malfunction of Control or Relief Equipment	3	0.9	1	-	1	2	35,000	100,000	135,000	12,803	-	-	-	1	1	1	-
Defective Pipe-Base Metal	3	0.9	-	-	-	-	725	75	800	993	-	1	-	1	-	1	-
Ruptured Gasket	11	3.2	-	-	-	-	1,656	1,100	2,756	2,112	1	-	1	-	-	7	2
Defective Girth Weld	3	0.9	-	-	-	-	300	100	400	986	-	2	1	-	-	-	-
Flood	1	0.3	-	-	-	-	160	0	160	2,300	-	-	-	1	-	-	-
Surge	7	2.0	-	-	-	-	406	1,550	1,956	5,737	2	-	1	1	2	1	-
Miscellaneous	20	5.8	-	-	-	-	173,129	3,610	176,739	283,691	2	1	1	6	5	3	2
TOTALS	347	100.0	1	3	4	17	463,016	436,212	899,228	521,849	48	53	51	60	78	51	6

Department of Transportation
Pipeline accidents from DOT Form 7000-1
January 1, 1970,-through December 31, 1970
Compiled by the Office of Pipeline Safety
April 1, 1971

BEGIN FIRST LINE OF TEXT HERE
DROPPED HEAD, STUB, SECTIONS HERE
CENTER OF PAGE
TOP OF IMAGE AREA
BEGIN LAST LINE OF TEXT
TYPING GUIDE SHEET

LIQUID PIPELINE ACCIDENT SUMMARY - January 1, 1970, THROUGH DECEMBER 31, 1970

CAUSE OF ACCIDENT	NO. OF ACCIDENTS	% OF TOTAL	DEATHS		INJURIES		PROPERTY DAMAGE ($)			LOSS OF COMMODITY (BARRELS)	NO. OF ACCIDENTS BY YEAR OF INSTALLATION						
			CARRIER EMPLOYEES	NON EMPLOYEES	CARRIER EMPLOYEES	NON EMPLOYEES	CARRIER	OTHER	TOTAL		Before 1920	1920-1929	1930-1939	1940-1949	1950-1959	1960-1969	Not Reported
Operation Accidents																	
Corrosion - External	149	42.8	-	-	1	4	27,329	41,092	68,421	43,232	36	34	30	26	13	9	1
Equipment Rupturing Line	70	20.2	-	1	1	1	61,375	58,125	119,500	80,121	4	8	10	11	26	11	[illegible]
Defective Pipe Seam	30	8.6	-	-	-	-	2,853	9,633	12,500	60,174	1	4	6	3	9	6	[illegible]
Corrosion - Internal	30	8.7	-	-	-	10	137,000	209,385	351,385	15,416	1	1	1	3	16	8	[illegible]
Incorrect Operation by Carrier Personnel	13	3.8	-	2	-	-	4,661	11,673	16,334	26,806	1	-	-	7	1	3	1
Rupture of Previously Damaged Pipe	5	1.4	-	-	-	-	18,200	0	18,200	1,410	-	-	-	-	2	3	-
Ruptured, Leaking, or Malfunction of Valve	3	0.9	-	-	-	-	87	600	687	3,479	-	-	-	-	3	-	-
Malfunction of Control or Relief Equipment	3	0.9	1	-	1	2	31,000	100,000	131,000	12,803	-	-	-	1	1	1	-
Defective Pipe-Base Metal	3	0.9	-	-	-	-	725	75	800	893	-	1	-	1	-	1	-
Ruptured Gasket	11	3.2	-	-	-	-	1,635	1,100	2,735	3,113	1	-	1	-	-	2	2
Defective Girth Weld	1	0.3	-	-	-	-	500	100	600	986	-	1	-	-	-	-	-
Flood	1	0.3	-	-	-	-	160	0	160	1,500	-	-	-	1	-	-	-
Surge	7	2.0	-	-	-	-	406	1,550	1,956	5,737	1	-	1	-	2	1	-
Miscellaneous	20	5.8	-	-	-	-	173,120	3,610	176,730	283,691	7	1	1	6	5	5	7
TOTALS	347	100.0	1	3	4	17	463,016	436,212	899,228	571,849	48	53	51	60	78	51	6

Department of Transportation
Pipeline accidents from DOT Form 7000-1
January 1, 1970, through December 31, 1970
Compiled by the Office of Pipeline Safety
April 1, 1971

SUMMARY - BY COMMODITY INVOLVED

COMMODITY	NO. OF ACCIDENTS	% OF TOTAL	LOSS (BARRELS)	% OF TOTAL	PROPERTY DAMAGE ($)				DEATHS		INJURIES	
					CARRIER	OTHERS	TOTAL	% OF TOTAL	CARRIER EMPLOYEES	NON EMPLOYEES	CARRIER EMPLOYEES	NON EMPLOYEES
OPERATIONS ACCIDENTS												
Crude Oil	216	62.2	383,160	73.4	333,719	79,987	413,756	46.0		1	1	
Gasoline	63	18.2	47,230	9.1	68,232	7,920	76,152	8.5	1			5
LPG	24	6.9	46,341	8.9	44,402	321,035	365,437	40.5		2	1	12
Fuel Oil	15	4.3	22,935	4.4	6,400	21,375	27,725	3.1				
Diesel Fuel	10	2.9	10,202	2.0	3,729	2,775	6,504	0.7				
Jet Fuel	9	2.6	6,116	1.2	1,339	470	1,809	0.2				
Anhydrous Ammonia	4	1.2	1,025	.2	25	800	825	.1			2	
Kerosine	2	.6	1,934	.3	1,750	700	2,450	.3				
Natural Gasoline	3	.8	2,806	.5	3,400	1,150	4,550	.6				
Propylene	1	.3	100	.0	20	0	20	.0				
TOTALS - DURING OPERATIONS	347	100.0	521,849	100.0	463,016	436,212	899,228	100.0	1	3	4	17

Department of Transportation
Pipeline accidents from DOT Form 7000-1
January 1, 1970, through December 31, 1970
Compiled by the Office of Pipeline Safety
April 1, 1971

LIQUID PIPELINE ACCIDENT SUMMARY - JANUARY 1, 1971, THROUGH DECEMBER 31, 1971

CAUSE OF ACCIDENT	NO. OF ACCIDENTS	% OF TOTAL	DEATHS		INJURIES		PROPERTY DAMAGE ($)			LOSS OF COMMODITY (BARRELS)	NO. OF ACCIDENTS BY YEAR OF INSTALLATION							
			CARRIER EMPLOYEES	NON EMPLOYEES	CARRIER EMPLOYEES	NON EMPLOYEES	CARRIER	OTHER	TOTAL		Before 1920	1920-1929	1930-1939	1940-1949	1950-1959	1960-1969	[illegible]	[illegible]
Operation Accidents																		
Corrosion - External	102	33.1	0	0	1	0	13,107	20,760	33,867	29,923	13	22	29	23	12	3	-	-
Equipment Rupturing Line	67	21.8	0	0	0	0	38,472(1)	163,305(5)	201,777	60,868	2	15	4	9	23	13	-	-
Defective Pipe Seam	31	10.1	0	0	0	0	9,303	22,100	31,403	36,299(8)	5	6	1	5	5	8	-	-
Corrosion - Internal	22	7.1	0	0	0	0	2,837	965	3,802	12,445(9)	-	3	7	1	2	8	-	-
Incorrect Operation by Carrier Personnel	22	7.1	0	0	0	4	54,450(2)	4,050	58,500	22,830(10)	-	2	2	6	6	3	-	-
Miscellaneous	12	3.8	0	0	1	0	8,179	1,925	10,104	10,216(11)	-	1	3	1	-	1	-	-
Ruptured or Leaking Gasket	7	2.3	0	0	0	1	24	150	174	2,115	-	1	1	-	3	1	-	-
Ruptured or Leaking Seal	6	2.0	0	0	0	0	140	50	190	3,362	-	-	-	-	2	1	-	-
Defective Repair Weld	6	2.0	0	0	0	0	3,475	9,800	13,275	22,575(12)	-	2	3	-	-	-	-	-
Unknown	6	2.0	0	1	0	0	159,000(3)	26,500(6)	185,500	7,962	-	1	1	-	2	2	-	-
Ruptured, Leaking, or Malfunction of Valve	5	1.6	0	0	0	0	1,660	1,200	2,860	12,070(13)	-	-	1	-	-	4	-	-
Rupture of Previously Damaged Pipe	4	1.3	0	0	0	0	1,200	26,000(7)	27,200	13,759(14)	-	-	1	-	1	1	-	-
Malfunction of Control or Relief Equipment	3	1.0	0	0	0	0	500	150	650	3,636	-	-	-	-	1	2	-	-
Cold Weather	3	1.0	0	0	0	0	11	505	516	810	-	-	-	3	-	-	-	-
Defective Girth Weld	3	1.0	0	0	0	1	2,516	900	3,416	520	-	-	1	2	-	-	-	-
Threads Stripped or Broken	3	1.0	0	0	0	0	220	550	770	775	-	-	-	-	3	-	-	-
Pump Packing Failure	2	.6	0	0	0	0	50	1,025	1,075	560	-	-	-	-	2	-	-	-
Vandalism	2	.6	0	0	0	0	30	5,000	5,030	280	-	-	-	1	-	1	-	-
Lightning	2	.6	0	0	0	0	105,200(4)	0	105,200	4,050	-	-	-	1	1	-	-	-
TOTAL	308	100.0	0	1	2	6	420,374	264,935	685,309	245,057	20	53	54	52	62	48	[illegible]	[illegible]

(1) Includes accidents of $10,000 and $11,000.
(2) Includes one accident of $50,000.
(3) Includes one accident of $150,000.
(4) Includes one accident of $105,000.
(5) Includes accidents of $60,000 and $52,800.
(6) Includes accidents of $15,000 and $10,000.
(7) Includes one accident of $25,000.

(8) Includes one accident with loss of 6,479 barrels.
(9) Includes one accident with loss of 5,500 barrels.
(10) Includes accidents with losses of 3,300 and 5,131 barrels.
(11) Includes one accident with loss of 5,300 barrels.
(12) Includes accidents with losses of 12,800 and 6,690 barrels.
(13) Includes one accident with loss of 7,390 barrels.
(14) Includes one accident with loss of 6,800 barrels.

Department of Transportation
Pipeline accidents from DOT Form 7000-1
January 1, 1971, through December 31, 1971
Compiled by the Office of Pipeline Safety

SUMMARY - BY COMMODITY INVOLVED

COMMODITY	NO. OF ACCIDENTS	% OF TOTAL	LOSS (BARRELS)	% OF TOTAL	PROPERTY DAMAGE ($)				DEATHS		INJURIES	
					CARRIER	OTHERS	TOTAL	% OF TOTAL	CARRIER EMPLOYEES	NON EMPLOYEES	CARRIER EMPLOYEES	NON EMPLOYEES
OPERATIONS ACCIDENTS												
Crude Oil	172	55.9	115,760 (1)	47.2	44,168 (4)	73,770 (5)	117,938	17.2	0	0	2	0
Gasoline	51	16.6	42,001	17.1	173,949 (6)	61,635 (7)	235,584	34.4	0	0	0	4
L.P.G.	39	12.7	39,887 (2)	16.3	70,184 (8)	76,000 (9)	146,184	21.3	0	0	0	0
Fuel Oil	21	6.8	13,724	5.6	11,072	9,905	20,977	3.1	0	0	0	0
Diesel Fuel	5	1.6	6,953	2.8	540	250	790	.1	0	0	0	0
Condensate	5	1.6	3,658	1.5	10,580	16,150 (10)	26,730	3.9	0	1	0	1
Jet Fuel	4	1.3	2,236	.9	4,385	1,000	5,385	.8	0	0	0	0
Natural Gasoline	4	1.3	8,743	3.6	105,024 (11)	25	105,049	15.3	0	0	0	0
Anhydrous Ammonia	3	1.0	9,810 (3)	4.0	0	25,000 (12)	25,000	3.7	0	0	0	1
Kerosine	2	.6	700	.3	400	1,000	1,400	.2	0	0	0	0
Alkylate	2	.6	1,585	.7	72	200	272	.0	0	0	0	0
TOTALS - DURING OPERATIONS	308	100.0	245,057	100.0	$420,374	$264,935	$685,309	100.0	0	1	2	6

(1) Includes accidents with losses of 12,800, 6,690, 7,390, 5,300, and 5,131 barrels.
(2) Includes accidents with losses of 6,479, 5,500, and 5,300 barrels.
(3) Includes one accident of 6,800 barrels.
(4) Includes one accident with property damage of $11,000.
(5) Includes one accident with property damage of $10,000.
(6) Includes one accident with property damage of $150,000.
(7) Includes one accident with property damage of $52,800.
(8) Includes accidents with property damages of $10,000 and $50,000.
(9) Includes one accident with property damage of $60,000.
(10) Includes one accident with property damage of $15,000.
(11) Includes one accident with property damage of $105,024.
(12) One accident of $25,000.

Department of Transportation
Pipeline accidents from DOT Form 7000-1
January 1, 1971, through December 31, 1971
Compiled by the Office of Pipeline Safety

LIQUID PIPELINE ACCIDENT SUMMARY - JANUARY 1, 1972, THROUGH DECEMBER 31, 1972

CAUSE OF ACCIDENT	NO. OF ACCIDENTS	% OF TOTAL	DEATHS		INJURIES		PROPERTY DAMAGE ($)			LOSS OF COMMODITY (BARRELS)	NO. OF ACCIDENTS BY YEAR OF INSTALLATION							
			CARRIER EMPLOYEES	NON EMPLOYEES	CARRIER EMPLOYEES	NON EMPLOYEES	CARRIER	OTHER	TOTAL		Before 1920	1920-1929	1930-1939	1940-1949	1950-1959	1960-1969	1970-1972	Not Rept.
OPERATION ACCIDENTS																		
Corrosion - External	75	24.3	0	2	1	2	13,100(1)	75,115(9)	88,215	60,673(15)	18	21	15	12	8	1	0	0
Equipment Rupturing Line	69	22.3	0	5	0	3	81,993(2)	41,135(10)	123,128	83,392(16)	4	6	6	12	20	17	4	0
Defective Pipe Seam	28	9.1	0	0	0	2	19,321	24,830(11)	44,151	43,303(17)	0	2	2	4	17	3	0	0
Corrosion - Internal	25	8.1	0	0	0	0	2,363	3,003	5,366	30,900(18)	0	3	0	0	7	15	0	0
Incorrect Operation by Carrier Personnel	22	7.1	0	0	5	6	1,305,955(3)	37,650(12)	1,343,605	45,885(19)	0	2	0	3	5	6	4	2
Miscellaneous	13	4.2	0	0	0	0	4,995	202,755(13)	207,750	13,070	0	1	1	1	3	3	4	0
Rupture of Leaking Gasket	8	2.6	0	0	0	0	590	650	1,240	2,138	0	0	0	0	2	3	3	0
Malfunction of Control or Relief Equipment	8	2.6	1	0	0	0	68,300(4)	1,700	70,000	5,143	0	0	0	1	3	2	1	1
Rupture of Previously Damaged Pipe	7	2.3	0	0	0	0	37,232(5)	2,500	39,732	33,257(20)	0	0	1	0	5	1	0	0
Cold Weather	6	2.0	0	0	0	0	280	200	480	1,809	0	0	0	0	1	3	1	1
Heavy Rains or Floods	6	2.0	0	0	0	0	125,002(6)	300	125,302	6,982	2	2	1	0	0	1	0	0
Ruptured or Leaking Seal	5	1.6	0	0	0	0	575	2,100	2,675	567	0	0	0	1	1	1	1	1
Threads Stripped or Broken	5	1.6	0	0	0	0	1,060	2,200	3,260	1,530	0	1	0	0	0	3	1	0
Vandalism	5	1.6	0	0	0	0	510	1,400	1,910	3,667	0	1	0	2	0	2	0	0
Pipe Coupling Failure	5	1.6	0	0	0	0	39,283(7)	68,100(14)	107,383	4,197	0	2	0	0	0	1	1	1
Defective Pipe	4	1.3	0	0	0	0	575	700	1,275	7,257	0	0	0	1	1	2	0	0
Defective Girth Weld	3	1.0	0	0	0	0	0	2,150	2,150	350	0	2	0	0	1	0	0	0
Freight Train Derailment	3	1.0	0	0	0	0	950	200	1,150	1,900	1	1	0	1	0	0	0	0
Defective Repair Weld	2	.6	0	0	0	0	505	525	1,030	216	0	0	1	0	1	0	0	0
Pump Packing Failure	2	.6	0	0	0	0	1,200	400	1,600	1,150	0	0	0	1	0	0	1	0
Lightning	2	.6	0	0	0	0	218,000(8)	3,000	221,000	23,000(21)	1	0	1	0	0	0	0	0
Defective Weld	2	.6	0	0	0	0	6,050	350	6,400	420	0	0	1	0	0	1	0	0
Explosives	2	.6	0	0	0	0	2,638	0	2,638	1,380	0	2	0	0	0	0	0	0
Surge of Electricity	2	.6	0	0	0	0	670	0	670	300	0	0	0	0	0	2	0	0
TOTAL	309	100.0	1	7	6	13	$1,931,047	470,965	2,402,012	360,654	26	46	29	39	75	67	21	6

(1) Includes accident of $10,000.
(2) Includes accidents of $20,000, $20,000, and $14,000
(3) Includes accidents of $1,250,000, $40,000, and $10,000.
(4) Includes accident of $60,000.
(5) Includes accident of $33,000.
(6) Includes accidents of $100,000, $12,500, and $12,500.
(7) Includes accident of $37,473.
(8) Includes accidents of $118,000, and $100,000.
(9) Includes accidents of $40,000, and $13,000.
(10) Includes accident of $10,000.
(11) Includes accident of $14,000.
(12) Includes accident of $30,000.
(13) Includes accident of $200,000.
(14) Includes accident of $67,900.
(15) Includes accidents with losses of 6,000 and 6,000 barrels.
(16) Includes accidents with losses of 8,000, 8,000, 7,211, 5,474, 5,200, and 5,000 barrels.
(17) Includes accidents with losses of 6,797 and 6,000 barrels.
(18) Includes accidents with losses of 13,100 and 10,260 barrels.
(19) Includes accidents with losses of 11,598, 6,915 and 6,875 barrels.
(20) Includes accidents with losses of 17,000, 8,000, and 5,010 barrels
(21) Includes one accident of 19,985 barrels.

EPA Form 2350-6 (4-80)
(PREVIOUSLY EIN. EPA FORM 287)
TYPING GUIDE SHEET

SUMMARY - BY COMMODITY INVOLVED

	NO. OF ACCIDENTS	% OF TOTAL	LOSS (BARRELS)	% OF TOTAL	PROPERTY DAMAGE ($)				DEATHS		INJURIES	
					CARRIER	OTHER	TOTAL	% OF TOTAL	CARRIER EMPLOYEES	NON EMPLOYEES	CARRIER EMPLOYEES	NON EMPLOYEES
OPERATIONS ACCIDENTS												
Crude Oil	180	58.3	233,690(1)	64.8	364,268(6)	396,530(11)	760,798	31.7	0	2	1	6
Gasoline	60	19.4	43,654(2)	12.1	1,366,615(7)	40,100(12)	1,406,715	58.4	0	0	5	4
Fuel Oil	25	8.1	17,924	5.0	38,404(8)	9,750	48,154	2.0	0	0	0	0
L.P.G.	22	7.1	30,409(3)	8.5	116,840(9)	16,710(13)	133,550	5.6	1	4	0	3
Diesel Fuel	8	2.6	10,882(4)	3.0	1,715	2,825	4,540	0.2	0	0	0	0
Jet Fuel	5	1.6	5,814	1.6	2,010	1,850	3,860	0.2	0	0	0	0
Condensate	4	1.3	5,869	1.6	540	2,400	2,940	0.1	0	0	0	0
Kerosene	3	1.0	10,200(5)	2.8	41,300(10)	800	42,100	1.8	0	0	0	0
Natural Gasoline	1	0.3	1,000	0.3	55	0	55	0	0	0	0	0
Alkylate	1	0.3	1,212	0.3	100	0	100	0	0	1	0	0
TOTALS - DURING OPERATIONS	309	100.0	360,654	100.0	$1,931,847	$470,965	$2,402,812	100.0	1	7	6	13

(1) Includes accidents with losses of 19,965, 17,000, 15,100, 11,598, 10,260, 8,000, 8,000, 8,000, 8,000, 7,211, 6,800, 6,797,6,000, and 5,200 barrels.
(2) Includes one accident of 6,915 barrels.
(3) Includes accidents with losses of 5,474, and 5,000 barrels.
(4) Includes one accident of 5,010 barrels.
(5) Includes one accident of 6,875 barrels.
(6) Includes accidents with property damages of $118,000, $100,000, $37,473, $33,000, $10,000, and $10,000.
(7) Includes accidents with property damages of $1,250,000, and $100,000.
(8) Includes accidents with property damages of $12,500, and $12,500.
(9) Includes accidents with property damages of $60,000, $20,000, $20,000, and $14,000.
(10) Includes one accident with property damage of $40,000.
(11) Includes accidents with property damages of $200,000, $67,900, $40,000, $14,000, and $13,000.
(12) Includes one accident with property damage of $30,000.
(13) Includes one accident with property damage of $10,000.

LIQUID PIPELINE ACCIDENT SUMMARY - JANUARY 1, 1973, THROUGH DECEMBER 31, 1973

CAUSE OF ACCIDENT OPERATION ACCIDENTS	NO. OF ACCIDENTS	% OF TOTAL	DEATHS CARRIER EMPLOYEES	DEATHS NON EMPLOYEES	INJURIES CARRIER EMPLOYEES	INJURIES NON EMPLOYEES	PROPERTY DAMAGE ($) CARRIER	PROPERTY DAMAGE ($) OTHER	PROPERTY DAMAGE ($) TOTAL	LOSS OF COMMODITY (BARRELS)	NO. OF ACCIDENTS BY YEAR INSTALLATION BEFORE 1920	1920-1929	1930-1939	1940-1949	1950-1959	1960-1969	1970-1973	NOT REPORTED
Corrosion - External	72	26.5	0	0	0	0	$ 9,824	$ 76,130(10)	$ 85,954	52,637(18)	13	22	16	9	7	5	0	0
Equipment Rupturing Line	66	24.2	0	0	0	0	33,096	94,512(11)	127,608	46,219	2	5	6	21	20	7	4	1
Defective Pipe Seam	21	7.7	0	0	0	0	20,286	12,795	33,081	105,303(17)	1	3	1	4	9	3	0	0
Incorrect Operation by Carrier Personnel	16	6.0	1	0	1	2	43,855(2)	1,430	45,285	63,144(16)	0	0	1	4	3	5	2	1
Corrosion - Internal	14	5.2	0	0	0	0	2,450	800	3,250	11,455	0	2	1	3	2	6	0	0
Miscellaneous	11	4.0	0	0	0	3	462,400(3)	8,800	471,200	4,153	1	1	0	2	1	3	3	0
Rupture of Previously Damaged Pipe	8	2.9	0	0	0	0	13,006(4)	2,200	15,206	19,381(19)	0	0	0	2	2	4	0	0
Heavy Rains or Floods	7	2.6	0	0	0	0	6,360	10,150(12)	24,500	10,017(20)	1	2	0	0	1	2	0	1
Failure in River Crossing(26)	5	1.8	0	0	0	0	0	0	0	6,300	0	0	1	1	2	0	0	1
Ruptured or Leaking Gasket	5	1.8	0	0	0	0	3,105	5,110	8,215	10,364(21)	0	0	1	0	0	2	1	1
Malfunction of Control or Relief Equipment	5	1.8	0	0	0	0	285	2,500	2,785	7,945(22)	0	0	0	1	2	0	2	0
Cold Weather	5	1.8	0	0	0	0	1,405	0	1,405	4,984	0	0	2	0	1	1	0	1
Threads Stripped or Broken	5	1.8	0	0	0	0	2,030	6,000	8,030	1,943	0	0	2	0	0	1	2	0
Defective Girth Weld	5	1.8	0	0	0	0	1,500	360	1,860	10,075(23)	0	1	0	1	1	2	0	0
Failure of Previously Welded Repairs	5	1.8	0	6(1)	0	2	5,535	15,650(13)	21,185	9,735(24)	0	1	2	1	0	1	0	0
Malfunction of Valve	5	1.8	0	0	0	0	209,200(5)	12,020(14)	221,220	3,000	0	0	0	0	2	3	0	0
Pump Failure	4	1.5	0	0	0	0	16,975(6)	400	17,375	487	0	0	0	0	1	2	1	0
Pipe Failed Due to Buckling	4	1.5	0	0	0	0	15,000(7)	3,000	18,000	2,025	0	0	1	0	1	2	0	0
Ruptured or Leaking Seal	2	.7	0	0	0	0	2	0	2	415	0	0	0	0	1	1	0	0
Tank Roof Drain Leaking	2	.7	0	0	0	0	200	0	200	370	0	0	0	0	1	0	1	0
Pipe Coupling Failure	2	.7	0	0	0	0	51,500(8)	0	51,500	1,010	0	0	0	0	0	2	0	0
Defective Pipe	2	.7	0	0	0	0	155	25,243(15)	25,398	14,300(25)	0	2	0	0	0	0	0	0
Lightning	2	.7	0	0	0	0	120,000(9)	0	120,000	2	0	0	0	0	2	0	0	0
TOTAL	273	100.0	1	6	1	7	$1,018,909	$285,930	$1,304,839	379,365	18	39	34	49	59	52	16	6

(1) All deaths caused by one accident.
(2) Includes accident of $42,500.
(3) Includes accidents of $250,000; $200,000; and $10,400.
(4) Includes accident of $10,100.
(5) Includes accident of $209,000.
(6) Includes accident of $13,000.
(7) Includes accident of $15,000.
(8) Includes accident of $50,000.
(9) Includes accident of $100,000.
(10) Includes accidents of $35,225 and $20,000.
(11) Includes accidents of $60,000 and $20,000.
(12) Includes accident of $10,000.
(13) Includes accident of $15,000.
(14) Includes accident of $11,220.
(15) Includes accident of $17,443.
(16) Includes one accident of 5,637 barrels.
(17) Includes accidents with losses of 30,185; 18,700; 17,000; 10,500; 6,633; and 5,000 barrels.
(18) Includes one accident of 47,243 barrels.
(19) Includes one accident of 8,648 barrels.
(20) Includes one accident of 5,812 barrels.
(21) Includes one accident of 6,000 barrels.
(22) Includes one accident of 5,000 barrels.
(23) Includes accidents with losses of 7,863 and 7,834 barrels.
(24) Includes one accident of 6,640 barrels.
(25) Includes one accident of 13,000 barrels.
(26) Includes four reported as cause unknown and one as fatigue failure.

EPA Form 2250-6 (4-80)
(PREVIOUSLY CIN. EPA FORM 287)
TYPING GUIDE SHEET

SUMMARY - BY COMMODITY INVOLVED

COMMODITY OPERATION ACCIDENTS	NO. OF ACCIDENTS	% OF TOTAL	LOSS (BARRELS)	% OF TOTAL	PROPERTY DAMAGE ($)				DEATHS		INJURIES	
					CARRIER	OTHER	TOTAL	% OF TOTAL	CARRIER EMPLOYEES	NON EMPLOYEES	CARRIER EMPLOYEES	NON EMPLOYEES
Crude Oil	155	56.7	208,373(1)	54.8	$ 288,652(6)	$122,428(10)	$ 411,080	31.5	0	0	0	0
Gasoline	51	18.7	40,201(2)	10.6	315,055(7)	19,182	334,237	25.6	0	0	0	0
L.P.G.	25	9.2	51,574(3)	13.6	257,387(8)	15,860(11)	273,247	21.0	1	6(14)	1	2
Fuel Oil	20	7.3	51,505(4)	13.6	147,149(9)	99,910(12)	247,059	18.9	0	0	0	0
Jet Fuel	9	3.3	13,121(5)	3.5	9,938	26,100(13)	36,038	2.8	0	0	0	0
Diesel Fuel	6	2.2	5,548	1.5	600	1,950	2,550	.2	0	0	0	0
Condensate	5	1.8	5,604	1.5	48	500	548	.0	0	0	0	3
Kerosene	1	.4	229	.1	0	0	0	.0	0	0	0	0
Anhydrous Ammonia	1	.4	3,210	.8	80	0	80	.0	0	0	0	2
TOTAL DURING OPERATIONS	273	100.0	379,365	100.0	$1,018,909	$285,930	$1,304,839	100.0	1	6	1	7

(1) Includes accidents with losses of 30,185; 18,700; 17,000; 13,000; 10,500; 6,000; 5,912; 5,637; and two at 5,000 barrels.
(2) Includes one accident of 8,648 barrels.
(3) Includes accidents with losses of 7,863; 7,534; 6,640; and 6,533 barrels.
(4) Includes one accident of 42,243 barrels.
(5) Includes one accident of 6,049 barrels.
(6) Includes accidents with property damage of $209,000; $10,400; and $10,100.
(7) Includes accidents with property damage of $250,000; $20,000; $15,000; and $13,000.
(8) Includes accidents with property damage of $200,000 and $50,000.
(9) Includes accidents with property damage of $100,000 and $42,500.
(10) Includes accidents with property damage of $35,225; $17,443; and $11,220.
(11) Includes one accident with property damage of $15,000.
(12) Includes accidents with property damage of $60,000; $20,000; and $10,000.
(13) Includes one accident with property damage of $20,000.
(14) All deaths caused by one accident.

LIQUID PIPELINE ACCIDENT SUMMARY - JANUARY 1, 1974, THROUGH DECEMBER 31, 1974

CAUSE OF ACCIDENT OPERATION ACCIDENTS	NO. OF ACCIDENTS	% OF TOTAL	DEATHS		INJURIES		PROPERTY DAMAGE ($)			LOSS OF COMMODITY (BARRELS)	NO. OF ACCIDENTS BY YEAR INSTALLATION							
			CARRIER EMPLOYEES	NON EMPLOYEES	CARRIER EMPLOYEES	NON EMPLOYEES	CARRIER	OTHER	TOTAL		BEFORE 1920	1920-1929	1930-1939	1940-1949	1950-1959	1960-1969	1970-1974	NOT REPORTED
Equipment Rupturing Line	78	30.5	0	0	0	0	$ 82,676(5)	$231,130(11)	$ 313,806	100,156(15)	2	7	10	16	17	25	6	0
Corrosion - External	52	20.3	0	0	4(3)	0	13,161	18,319	31,480	21,309	2	12	18	6	8	7	0	1
Incorrect Operation by Carrier Personnel	28	10.9	0	0	2	3(4)	49,665(6)	1,400	51,065	20,957	0	3	3	0	4	16	6	0
Defective Pipe Seam	20	7.8	0	0	0	0	17,963	48,975(12)	66,938	49,631(16)	0	4	1	7	4	4	0	0
Corrosion - Internal	15	5.9	0	0	0	0	2,300	1,600	3,900	3,901	0	1	4	6	4	1	1	0
Failure of Previously Damaged Pipe	8	3.1	0	0	0	2	19,265(7)	21,668(13)	40,933	19,918(17)	0	0	0	1	1	6	0	0
Malfunction of Control or Relief Equipment	5	2.0	0	0	0	0	193,000(8)	500	193,500	2,735	0	0	0	0	0	3	1	1
Subsidence or Landslide	5	2.0	0	0	0	0	3,090	150	3,240	5,535	1	0	1	1	1	1	0	0
Defective Girth Weld	4	1.6	0	0	0	0	1,150	1,700	2,850	3,839	0	1	0	1	0	2	0	0
Vandalism	4	1.6	0	0	0	0	3,025	100	3,125	275	0	1	1	0	0	2	0	0
Malfunction of Valve	3	1.2	0	0	0	0	41,000(9)	0	41,000	9,519(18)	0	0	0	1	1	0	1	0
Threads Stripped or Broken	3	1.2	0	0	0	0	300	1,200	1,500	725	0	0	1	0	1	0	1	0
Cold Weather	2	.8	0	0	0	0	1,070	0	1,070	620	0	0	0	0	1	1	0	0
Failure of Previously Weld Repair	2	.8	4(1)	2(1)	0	0	0	300	300	310	0	0	1	0	1	0	0	0
Lightning	2	.8	0	0	0	0	5,000	0	5,000	165	0	0	0	1	1	0	0	0
Tank Roof Drain Failed to Work	2	.8	0	0	0	0	550	0	550	1,220	0	0	0	1	1	0	0	0
Miscellaneous	23	8.7	0	4(2)	0	0	879,397(10)	361,205(14)	1,240,602	53,701(19)	0	1	4	5	5	8	0	3
TOTAL	256	100.0	4	6	6	5	$1,313,182	$688,273	$2,001,455	293,643	5	30	43	44	71	96	22	4

(1) All deaths caused by one accident.
(2) All deaths caused by one accident.
(3) All injuries caused by one accident.
(4) All injuries caused by one accident.
(5) Includes accidents of $29,000 and $20,000.
(6) Includes accident of $40,000.
(7) Includes accident of $17,770.
(8) Includes accidents of $175,000 and $10,000.
(9) Includes accidents of $21,000 and $15,000.
(10) Includes accidents of $360,000; $200,000; $100,000; $50,000; and $20,000.
(11) Includes accidents of $95,000; $65,000; $30,000; $16,000; and $13,000.
(12) Includes accident of $30,000.
(13) Includes accident of $18,300.
(14) Includes accidents of $350,000 and $10,000.
(15) Includes accidents with losses of 40,000; 5,720; and 5,457 barrels.
(16) Includes accidents with losses of 7,700; 7,500; 6,900; and 6,750 barrels.
(17) Includes one accident of 6,000 barrels.
(18) Includes one accident of 5,130 barrels.
(19) Includes accidents with losses of 25,000 and 7,000 barrels.

EPA Form 2350-4 (4-80)
(PREVIOUSLY CIN. EPA FORM 337)
TYPING GUIDE SHEET

SUMMARY - BY COMMODITY INVOLVED

COMMODITY OPERATION ACCIDENTS	NO. OF ACCIDENTS	% OF TOTAL	LOSS (BARRELS)	% OF TOTAL	PROPERTY DAMAGE ($)			% OF TOTAL	DEATHS		INJURIES	
					CARRIER	OTHER	TOTAL		CARRIER EMPLOYEES	NON EMPLOYEES	CARRIER EMPLOYEES	NON EMPLOYEES
Crude Oil	166	64.9	168,730(1)	57.5	$ 554,793(4)	$ 80,873(7)	$ 635,666	31.8	4(11)	6(12)	0	0
L.P.G.	30	11.7	64,081(2)	21.8	677,539(5)	533,100(8)	1,210,639	60.5	0	0	4(13)	2
Gasoline	27	10.5	26,773	9.1	61,861(6)	6,000	67,861	3.4	0	0	0	0
Fuel Oil	16	6.3	13,225	4.5	4,020	55,200(9)	59,220	2.9	0	0	0	0
Jet Fuel	8	3.1	15,271(3)	5.2	9,989	11,200(10)	21,189	1.1	0	0	0	0
Diesel Fuel	6	2.3	1,278	.4	4,700	200	4,900	.2	0	0	0	0
Anhydrous Ammonia	2	.8	3,240	1.1	200	1,500	1,700	.1	0	0	0	3(14)
Condensate	1	.4	1,045	.4	80	200	280	.0	0	0	0	0
TOTAL DURING OPERATIONS	256	100.0	293,643	100.0	$1,313,182	$688,273	$2,001,455	100.0	4	6	4	5

(1) Includes accidents with losses of 40,000; 7,700; 7,500; 7,000; 6,900; 6,750; and 5,109 barrels.
(2) Includes accidents with losses of 25,000; 6,000; and 5,700 barrels.
(3) Includes one accident of 5,457 barrels.
(4) Includes accidents of $200,000; $175,000; $50,000; $25,000; $21,800; and $20,000.
(5) Includes accidents of $500,000; $100,000; $20,000; $18,000; $17,000; and $15,000.
(6) Includes accident of $40,000.
(7) Includes accidents of $20,000 and $10,000.
(8) Includes accidents of $350,000; $95,000; $65,000; and $18,000.
(9) Includes accidents of $30,000 and $18,000.
(10) Includes accident of $10,000.
(11) All deaths caused by one accident.
(12) All deaths caused by two accidents.
(13) Four injuries caused by one accident.
(14) All injuries caused by one accident.

TYPING GUIDE SHEET

LIQUID PIPELINE ACCIDENT SUMMARY - JANUARY 1, 1975, THROUGH DECEMBER 31, 1975

CAUSE OF ACCIDENT OPERATION ACCIDENTS	NO. OF ACCIDENTS	PERCENT OF TOTAL	DEATHS		INJURIES		PROPERTY DAMAGE ($)			LOSS OF COMMODITY (BARRELS)	NUMBER OF ACCIDENTS BY YEAR OF INSTALLATION							NOT REPORTED
			CARRIER EMPLOYEES	NON EMPLOYEES	CARRIER EMPLOYEES	NON EMPLOYEES	CARRIER	OTHER	TOTAL		BEFORE 1920	1920-1929	1930-1939	1940-1949	1950-1959	1960-1969	1970-1975	
Equipment Rupturing Line(3)	73	28.6	0	0	0	1	$ 375,110	$266,571	$ 641,681	83,724	3	0	3	10	14	21	3	1
Corrosion - External	57(1)	22.4	0	0	0	0	88,931	26,850	115,781	37,073	2	10	17	14	9	3	1	1
Equipment Failure(4)	27	10.6	3	0	3	0	534,010	9,081	543,091	20,081	0	0	2	1	2	10	8	4
Incorrect Operation by Carrier Personnel(5)(6)	22(2)	8.6	0	0	0	0	654,705	128,150	782,855	26,610	0	1	3	3	1	8	5	1
Corrosion - Internal	15(1)	5.9	0	0	0	0	2,850	2,550	5,400	2,053	0	6	0	2	2	6	0	0
Defective Pipe Seam(7)	15(2)	5.9	0	0	0	0	2,219	12,650	14,869	61,576	0	2	3	4	2	7	1	0
Defective Girth Weld	5	2.0	0	0	0	0	4,150	2,015	6,165	30,131	0	0	3	0	1	1	0	0
Failure of Previously Damaged Pipe(8)(9)	4	1.6	0	4	0	0	20,260	363,000	383,260	31,665	0	0	1	0	1	1	1	0
Vandalism	4	1.6	0	0	0	0	3,505	15	3,520	604	0	0	1	2	0	1	0	0
Failure of Previous Weld Repair	2	0.7	0	0	0	0	17,450	1,500	18,950	3,720	0	0	0	0	1	1	0	0
Lightning(10)	2	0.7	0	0	0	9	297,500	0	297,500	11,356	1	0	0	1	0	1	0	0
Miscellaneous(11)	29	11.4	0	0	0	2	380,429	3,500	383,929	8,020	1	1	2	4	0	11	7	3
TOTAL	255	100.0	3	4	3	12	$2,382,100	$814,882	$3,197,681	339,433	7	20	35	50	33	71	26	10

(1) One accident had both external and internal corrosion as the cause. Damages and loss of commodity are included in external corrosion caused group.

(2) Four accidents had both incorrect operation by carrier personnel and defective pipe seam as the cause. Damages and loss of commodity have been included in the incorrect operation by carrier personnel caused group.

(3) Accidents with property damages of $181,000; $130,650; $85,000; and $94,300.

(4) One accident--two deaths, three injuries, and $160,000 carrier property damage; another accident--one death and $300,000 carrier property damage; and another accident--$125,000 carrier property damage.

(5) One accident had total damages of $775,000.

(6) Two accidents had a commodity loss of 10,048 barrels (4,000 and 6,048).

(7) Three accidents had a commodity loss of 32,789 barrels (12,802, 10,000, and 9,987).

(8) One accident--four deaths and 25,500 barrels of commodity lost.

(9) One accident--nine injuries and $325,000 other property damages.

(10) One accident had two tanks (1917 and 1964) struck by lightning, destroyed by fire--$295,000 carrier property damage.

(11) One accident--one injury and $350,000 carrier property damage.

EPA Form 2350-4 (4-80)
TYPING GUIDE SHEET

SUMMARY - BY COMMODITY INVOLVED

COMMODITY	NO. OF ACCIDENTS	PERCENT OF TOTAL	LOSS IN BARRELS	PERCENT OF TOTAL	PROPERTY DAMAGE ($)			PERCENT OF TOTAL	DEATHS		INJURIES	
					CARRIER	OTHER	TOTAL		CARRIER EMPLOYEES	NON EMPLOYEES	CARRIER EMPLOYEES	NON EMPLOYEES
Crude Oil(1)	135	52.9	105,871	33.14	$1,293,923	$147,841	$1,441,764	45.1	1	0	0	1
Gasoline(2)	41	16.1	30,843	9.7	771,223	134,281	905,504	28.3	0	0	0	1
Fuel Oil	29	11.4	24,386	7.63	38,401	14,000	52,401	1.6	0	0	0	0
L.P.G.(3)	26	10.2	105,228	32.94	269,870	416,000	685,870	21.5	2	4	3	10
Jet Fuel	7	2.7	4,249	1.33	462	5,000	5,462	0.2	0	0	0	0
Natural Gasoline	7	2.7	21,475	6.73	916	94,210	95,126	2.96	0	0	0	0
Kerosene	4	1.6	25,030	7.84	6,919	2,150	9,069	0.28	0	0	0	0
Anhydrous Ammonia	3	1.2	1,311	0.41	10	1,000	1,010	0.03	0	0	0	0
Condensate	2	0.8	850	0.27	475	100	575	0.02	0	0	0	0
Transmix	1	0.4	180	0.01	0	300	300	0.01	0	0	0	0
TOTAL	255	100.0	319,423	100.0	$2,382,190	$814,882	$3,197,081	100.0	3	4	3	12

(1) Accidents--$300,000 property damage and one carrier employee death; $151,000 property damage; $295,000 property damage and 11,356 barrels of commodity lost; 15,000 barrels of commodity lost; $250,000 property damage and one nonemployee injury; $85,000 property damage; and $125,100 property damage.

(2) Accidents--$59,431 property damage and 4,122 barrels of commodity lost and $775,000 property damage.

(3) Accidents--$58,000 property damage, four nonemployee deaths, and 25,500 barrels of commodity lost; $130,650 property damage and one nonemployee injury; $325,055 property damage and nine nonemployee injuries; and $100,000 property damage, two carrier employee deaths, and three carrier employee injuries.

TYPING GUIDE SHEET

LIQUID PIPELINE ACCIDENT SUMMARY - JANUARY 1, 1976, THROUGH DECEMBER 31, 1976

CAUSE OF ACCIDENT OPERATION ACCIDENTS	NO. OF ACCIDENTS	% OF TOTAL	DEATHS		INJURIES		PROPERTY DAMAGE ($)			LOSS OF COMMODITY (BARRELS)	NUMBER OF ACCIDENTS BY YEAR OF INSTALLATION							
			CARRIER EMPLOYEES	NON EMPLOYEES	CARRIER EMPLOYEES	NON EMPLOYEES	CARRIER	OTHER	TOTAL		BEFORE 1920	1920-1929	1930-1939	1940-1949	1950-1959	1960-1969	1970-1976	NOT REPORTED
quipment Rupturing Line	67	32.0	0	0	0	0	$ 83,929(3)	$110,920(7)	$ 194,849	74,590(13)	2	7	7	16	21	11	3	0
orrosion - External	41	19.6	0	0	0	0	11,810	20,200(8)	32,010	31,956(14)	5	6	8	9	7	3	1	2
ncorrect Operation by Carrier Personnel	20	9.6	0	0	1	0	11,284	68,300(9)	79,584	40,155(15)	1	3	1	3	3	6	3	0
efective Pipe Seam	14	6.7	0	5(1)	1	0	4,202	25,405(10)	29,607	38,494(16)	0	0	0	3	5	6	0	0
Corrosion - Internal	10	4.8	0	0	0	0	151,910(4)	2,000	153,910	3,249	2	0	3	2	1	1	0	1
Failure of Previously Damaged Pipe	7	3.3	0	0	2(2)	0	47,173(5)	120,035(11)	167,208	20,070(17)	0	0	0	1	4	2	0	0
Malfunction of Control or Relief Equipment	1	0.5	0	0	0	0	0	0	0	335	0	0	0	1	0	0	0	0
Defective Girth Weld	4	1.9	0	0	1	0	1,665	5,510	7,175	13,025(18)	0	2	1	0	0	1	0	0
Vandalism	3	1.4	0	0	0	0	69	2,250	2,319	7,428(19)	0	0	1	0	0	2	0	0
Malfunction of Valve	4	1.9	0	0	0	0	2,500	1,000	3,500	2,521	0	0	1	2	0	0	1	0
Threads Stripped or Broken	2	1.0	0	0	0	0	0	50,000(12)	50,000	328	0	0	0	1	0	0	1	0
Cold Weather	5	2.4	0	0	0	0	1,505	475	1,980	4,365	1	0	1	0	1	0	2	0
Pump or Appurtenance Facilities	5	2.4	0	0	0	0	10	200	210	1,550	0	0	1	1	0	2	1	0
Lightning	1	0.5	0	0	0	0	6,550	0	6,550	0	0	0	0	0	1	0	0	0
Tank or Appurtenance Facilities	5	2.4	0	0	0	0	4,600	0	4,600	1,560	0	0	0	1	1	1	1	1
Motor Vehicle	1	0.5	0	0	0	0	100	0	100	499	0	0	0	0	1	0	0	0
Miscellaneous	19	9.1	0	0	0	0	891,795(6)	5,400	897,195	15,014(20)	0	0	3	2	3	6	3	2
TOTAL	209	100.0	0	5	5	0	$1,219,102	$411,695	$1,630,797	255,027	11	18	27	42	48	41	16	6

(1) All deaths caused by one accident.
(2) All injuries caused by one accident.
(3) Includes accident of $25,000.
(4) Includes accident of $150,000.
(5) Includes accident of $40,000.
(6) Includes accidents of $750,000; $100,000; and $35,000.
(7) Includes accidents of $75,000 and $11,000.
(8) Includes accident of $13,000.
(9) Includes accidents of $50,000 and $12,000.
(10) Includes accident of $15,000.
(11) Includes accidents of $100,000 and $20,000.
(12) One accident.
(13) Includes accidents with losses of 9,271; 5,236; 4,652; and 4,336 barrels.
(14) Includes accidents with losses of 9,232 and 5,000 barrels.
(15) Includes accidents with losses of 24,305 and 4,059 barrels.
(16) Includes accidents with losses of 5,597; 5,415; 5,387; and 5,250 barrels.
(17) Includes accidents with losses of 6,000; 5,000; and 4,537 barrels.
(18) Includes accidents with losses of 6,125 and 5,000 barrels.
(19) Includes accident with loss of 6,578 barrels.
(20) Includes accident with loss of 6,997 barrels.

SUMMARY - BY COMMODITY INVOLVED

COMMODITY OPERATION ACCIDENTS	NO. OF ACCIDENTS	% OF TOTAL	LOSS (BARRELS)	% OF TOTAL	PROPERTY DAMAGE ($)			% OF TOTAL	DEATHS		INJURIES	
					CARRIER	OTHER	TOTAL		CARRIER EMPLOYEES	NON EMPLOYEES	CARRIER EMPLOYEES	NON EMPLOYEES
Crude Oil	123	58.9	96,059(1)	37.7	100,868(7)	137,655(10)	238,523	14.6	0	0	2(16)	0
Gasoline	39	18.7	29,674(2)	11.6	170,997(8)	6,710	177,707	10.9	0	0	0	0
N.G.L.	5	2.4	29,025(3)	11.4	1,185	28,030(11)	29,215	1.8	0	5(15)	2	0
Fuel Oil	13	6.2	43,497(4)	17.0	2,936	17,950(12)	20,886	1.3	0	0	0	0
L.P.G.	14	6.7	30,615(5)	12.0	930,295(9)	115,850(13)	1,046,145	64.1	0	0	1	0
Jet Fuel	3	1.4	1,788	0.7	3,200	0	3,200	0.2	0	0	0	0
Diesel Fuel	7	3.3	13,096	5.1	2,360	3,500	5,860	0.3	0	0	0	0
Anhydrous Ammonia	3	1.4	10,149(6)	4.0	7,240	52,000(14)	59,240	3.6	0	0	0	0
Transmix	1	0.5	228	0.1	0	50,000	50,000	3.1	0	0	0	0
Kerosene	1	0.5	906	0.4	21	0.	21	0.0	0	0	0	0
TOTAL	209	100.0	255,037	100.0	1,219,102	411,695	1,630,797	100.0	0	5	5	0

(1) Includes accidents with losses of 9,271; 6,578; 5,250; 5,236; 5,000; and 4,336 barrels.
(2) Includes one accident of 6,997 barrels.
(3) Includes accidents with losses of 9,222; 6,125; and 5,415 barrels.
(4) Includes accidents with losses of 24,305 and 4,537 barrels.
(5) Includes accidents with losses of 6,500; 5,597; and 4,859 barrels.
(6) Includes one accident of 4,652 barrels.
(7) Includes accident of $25,000.
(8) Includes accident of $150,000.
(9) Includes accidents of $750,000; $100,000; $40,000; and $35,000
(10) Includes accident of $75,000.
(11) Includes accidents of $15,000 and $13,000.
(12) Includes accident of $12,000.
(13) Includes accidents of $100,000 and $13,000.
(14) Includes accident of $50,000.
(15) All deaths caused by one accident.
(16) All injuries caused by one accident.

EPA Form 2350-4 (4-80)
TYPING GUIDE SHEET

APPENDIX D

A STATISTICAL ESTIMATE OF PIPELINE LEAKAGE

D.1 BACKGROUND

A statistical methodology for estimating the frequency and magnitude of pipeline leaks utilizing reported data is presented. The particular data base used consists of a computerized compilation prepared by SAI personnel containing key data on all oil spills reported to the Office of Pipeline Safety for the years 1971 through 1975 inclusive.

In the absence of a related fire, explosion or pollution, the OPSO data does not include data on spills under 50 barrels. It is the objective of the methodology discussed here to supply a reasonable estimate for the frequency of occurrence and magnitude of spills falling below this 50 barrel reporting threshold. The study estimates that about 70 percent of all spills from crude pipelines fall below 50 barrels. In terms of oil lost, this amounts to about two percent of the total spillage. It should be noted, however, that 70 percent is based on the types and causes of spills reported. Thus, there is an absence in OPSO spill data of causes of small leaks, such as at small fittings, sensor taps into the line, etc. Thus, this 70 percent figure is a minimal number and it is estimated that if all line spill causes are included the 70 percent figure would be increased upward to the 80 to 85 percent range.

D.2 ASSUMPTIONS

Two primary assumptions underlie the method. First, it is assumed that the OPSO data base is a fair representation of actual fact. It is assumed that all leaks exceeding the 50 barrel reporting threshold are reported, and that their magnitudes are determined without bias. Lack of bias is more important than simple error of estimation. For example, the data does not indicate groupings or clusterings of spill volumes about convenient numbers. A great many spills are reported as "50,", "100," or "200" barrels, for example, but very few or none as "52" or "97," etc. By assuming no bias, it is meant that these groupings are a result of honest estimation to the nearest reasonable number rather than a result of an attempt to consistently exaggerate or play down the size of spills. The correctness of this assumption weighs more heavily on the accuracy of the derived estimate than on the validity of the approach in general.

The second assumption is that the nature of the distribution of reported spills over 50 barrels is shared by spills below the 50 barrel reporting threshold. This assumption will be supported by the degree to which the observed data (reported spills) fit a meaningful probability density function and by observing that the same contributing physical laws which control the magnitude of spills over 50 barrels are operable in controlling the magnitude of spills under 50 barrels.

D.3 STATISTICAL ESTIMATION (CRUDE SPILLS)

Table D-1 is a summary of all reported spills from U.S. crude pipelines over the five years 1971 through 1975 inclusive. This summary was extracted from OPS data which includes spills from all parts of a pipeline system: the pipes, pumping stations, delivery points, tanks, valves, etc. The data presented in Table D-1 is limited to spills from the pipes themselves, excluding all other sources.

Attempts were made to fit alternative probability density functions to the five-year spill data. The primary density functions considered were the gamma and the log-normal. These two were selected because they share the property of having a fixed lower bound (there are no negative valued spills) and because they result "naturally" from certain intuitive and reasonable bases.

The gamma distribution is a generalization of the exponential distribution. If all spills were generated by the same size leaks (same leak rates) and the difference in magnitudes between spills were solely attributable to the time from inception to system shutdown, and if the likelihood of detection and shutdown remained constant with time, then it would follow that the exponential distribution would underlie the distribution of spill sizes. The gamma distribution, being the parent distribution of the exponential distribution, was thus considered as a meaningful and "natural" candidate for trial.

The log-normal distribution results when a random variable is itself the product of many other random variables, just as a normal (or Gaussian) random variable results from the sum of many other random variables. It is seen immediately that the two major factors determining the magnitude of a pipeline spill, namely leak rate and time to system shutdown, contribute multiplicatively to spill volume. That is: magnitude = rate x time. Additionally, leak rate is proportional to the product of the opening of the pipe (area) and the square root of the pipeline gage pressure. Time till detection of the leak (and hence system shutdown) is also conceivably the result of the product of several factors such as leak detection resolution (through the use of line variance measurements, etc.), total line flow rate, and, of course, leak rate.

In attempting to fit gamma and log normal distributions to the historical data, it was necessary to estimate the total number of spills (reported as well as unreported) while simultaneously determining the controlling parameters of the candidate distribution. The results of our investigation found an extremely close fit of the historical data is achieved with the log-normal distribution. We will therefore discuss our method of parameter

TABLE D-1. CRUDE SPILLS FROM LINE PIPE (NO. OF SPILLS)

Range (Barrels)	1971	1972	1973	1974	1975	5-Year Total
50-100	36	37	27	44	23	167
100-200	35	28	25	28	27	143
201-400	26	19	18	24	13	100
401-800	21	22	19	16	11	89
801-1600	14	11	13	12	6	56
1600-25000	14	24	20	19	8	85
	146	141	122	143	88	640

estimation utilizing this distribution. The method was applied in similar fashion with the gamma distribution. The log-normal distribution is defined:

$$f(x;\mu,\alpha) = \frac{1}{\sigma x\sqrt{2\pi}} \exp\left[-\frac{1}{2\sigma^2}(\ln x - \mu)^2\right]$$

where

$x > 0$

$\sigma > 0$

$-\infty < \mu < \infty$.

Now let a_i, $i = 1,2,\ldots, n+1$ denote the end points of n intervals of spill volume

b_i, $i = 1,2,\ldots, n$ denote the historical data values (spills) for each interval.

The intervals are defined in terms of spill magnitude. For example, we used $a_1 = 0$, $a_2 = 50$, or the magnitudes 0 to 50 barrels for the first interval, $a_2 = 50$ to $a_3 = 100$ for the second interval, and so on.

The determination of best possible fit was measured using χ^2 values as follows (χ^2 denotes the chi-square variable as used to test statistical hypotheses. See Section 6.2 for additional development.) For given values of μ and σ (the log-normal parameters) together with T, an assumed number of total spills, define F_i as:

$$F_i = \int_{a_i}^{a_{i+1}} f(x;\mu,\sigma)dx$$

or the probability that a spill falls in the ith interval, and

$$\chi^2 = \sum_{i=2}^{n} \frac{(b_i - F_iT)^2}{F_iT} \quad . \qquad (1)$$

Again, b_i is the actual spill frequency in the ith interval, while F_iT is the estimated frequency based upon the assumed values of μ, σ and T.

A program was developed which found the optimal values of μ, σ and T, minimizing χ^2 for the historical data. This program utilized a three level search or optimization scheme.

- Values for μ were determined by direct trial, stepping through a range of values.
- Values for σ were determined by utilizing a Fibonacci search to seek the best σ for each μ.
- Values of T were determined analytically for each pair: μ,σ. The values of μ and σ determine the values of F_i in equation (1). The optimal value of T is then found by differentiating (1).

$$\chi^2 = T \sum_{i=2}^{n} F_i - 2 \sum_{i=2}^{n} b_i + \frac{1}{1} \sum_{i=2}^{n} b_i^2/F_i \qquad \text{(from (1))}$$

$$\frac{d(\chi^2)}{dT} = \sum_{i=2}^{n} F_i - \frac{1}{T^2} \sum b_i^2/F_i$$

and setting

$$\frac{d(\chi^2)}{dT} = 0 \text{ yields}$$

$$T = \sqrt{\left(\sum b_i^2/F_i\right) \sum / F_i} \qquad (2)$$

The optimal values determined for the five-year data in Table D-1 were:

$\mu = 2.31$

$\sigma = 2.94$

$T = 2217.48$

The χ^2 value was 1.65. A comparison of the actual and predicted values is given in Table D-2.

Utilizing this log-normal distribution we generated Table D-3 which provides actual versus predicted spill frequencies for each of the five years, together with an estimate of barrels spilled for each interval. Table D-3 also provides the resulting estimates for spill frequencies and losses for the 0 to 50 barrel range. In generating these estimates the basic parameters (μ and σ) of the log-normal distribution remained unchanged.

TABLE D-2. LOG-NORMAL COMPARISON WITH FIVE-YEAR DATA

Index (i)	Range (barrels) $a_i - a_{i+1}$	Number of Spills Prediction F_iT	 Actual b_i	Difference
2	50 - 100	167.22	167	0.22
3	100 - 200	139.23	143	-3.77
4	200 - 400	109.68	100	9.68
5	400 - 800	81.75	89	-7.25
6	800 - 1600	57.66	56	1.66
7	1600 - 25000	85.28	85	0.28

TABLE D-3. PREDICTED AND ACTUAL SPILL FREQUENCIES

Interval Range	1971			1972			1973			1974			1975			Five-Year Totals		
	Actual	Pred[a]	Barrels	Actual	Pred	Barrels	Actual	Pred	Barrels	Actual	Pred	Barrels	Actual	Pred	Barrels	Actual	Pred	Barrels
0 - 10	--	239	629	--	232	611	--	201	528	--	234	615	--	147	387	--	1042	2,739
10 - 20	--	47	684	--	46	664	--	40	574	--	46	669	--	29	421	--	207	2,977
20 - 30	--	27	659	--	26	640	--	22	553	--	26	644	--	16	405	--	116	2,869
30 - 40	--	18	632	--	18	614	--	15	531	--	18	618	--	11	389	--	79	2,751
40 - 50	--	14	607	--	13	590	--	11	510	--	13	594	--	8	374	--	59	2,644
50 - 100	36	38	2,746	37	37	2,666	27	32	2,306	44	38	2,685	23	24	1,689	167	167	11,955
100 - 200	35	32	4,557	28	31	4,426	25	27	3,827	28	31	4,456	27	20	2,804	143	139	19,843
200 - 400	26	25	7,158	19	24	6,951	18	21	6,011	24	25	6,999	13	15	4,404	100	110	31,164
400 - 800	21	19	10,636	22	18	10,330	19	16	8,932	16	18	10,401	11	12	6,544	83	82	46,310
800 - 1600	14	13	14,955	11	13	14,524	13	11	12,559	12	13	14,623	6	8	9,201	56	58	65,113
1600 - 25000	14	20	107,173	24	19	104,082	20	16	90,002	19	19	104,798	8	12	65,937	85	85	466,630

[a] Log-normal estimate (prediciton)

Expression (2) was utilized to generate the total number of spills for each reporting period.

D.4 DISCUSSION OF RESULTS

In review and summary, a survey of alternative candidate distributions to model the pipeline leak process showed a remarkable ability of the log-normal distribution to fit the observed historical data. Fitting the historical data alone was not considered adequate, however. There are, for example, many so-called empirical distributions available to a researcher interested in modeling a given process. These empirical distributions can be manipulated so as to fit virtually any observed data. The degree of fit is limited only by the ingenuity and industry of the researcher. Empirical distributions are particularly useful for summarizing data when no clear-cut theoretical explanation is available. Since the historical data on pipeline spills is incomplete, and since the objective in this case is to estimate the magnitude of the missing data, it follows that the probability density function used to generate the estimate should possess a reasonable theoretical basis. Degree of fit is secondary and serves to validate the use of the suggested distribution.

Our approach, as discussed earlier, was to try several likely distributions without excessive regard for theoretical explanations. The aim was to first see if any of the "natural" distributions adequately fit the data. The two best candidates in terms of fit, the gamma and the log-normal, also had the strongest underlying justifications. Of the two, only the log-normal exhibited a "good" fit by common statistical standards.

Having discovered the ability of the log-normal distribution to fit the observed data we now reverse our discussion and hypothesize that the magnitude of crude pipeline spills is distributed log-normally. With some unavoidable repetition we will defend this hypothesis.

D.4.1 Characteristics of the Log-Normal Distribution

Since a primary objective of modeling the pipeline leak process is to estimate the frequency of events for which direct data is not available, it is necessary that the hypothesis (of log-normality) exhibit a reasonable theoretical foundation. Not only must the log-normal distribution fit the observed data over reported ranges, but there must also be a reasonable explanation to justify extension of the distribution into ranges void of data.

The log-normal distribution can be derived as the model for a process whose value results from the multiplication of contributing factors just as the normal distribution is derived as the limiting form of a process whose value results from the addition of contributing factors. In the case of the normal distribution, the well known Central Limit Theorem shows that the individual distributions of the contributing factors (random variates) does not affect the resulting normal tendency of the sum. A simple example is the sum of heads achieved in a sequence of flips of a "fair" coin. Each individual trial (flip) is a binary distribution with only two possible and equally likely outcomes. The sum of "heads" is a binomial distribution which approaches the normal distribution as the number of trials increases. An equivalent "central limit theorem" exists for the log-normal distribution (ref., The Log-Normal Distribution, J. Aitchison and J.A.C. Brown, Cambridge University Press, Cambridge, 1957).

The log-normal distribution is the model of a random process variate whose logarithm follows the normal distribution with parameters μ (mean) and σ (standard deviation). Thus, if $y = \ln x$ is normally distributed, the probability density function $g(y)$ for y is:

$$g(y) = \frac{1}{\sigma\sqrt{2\pi}} \exp - \left[\frac{1}{2\sigma^2}(y-\mu)^2\right] \; ; -\infty < y < \infty \quad .$$

Since $y = \ln x$ is equivalent to $x = e^y$ which is a strictly increasing function of y, we can transform $g(y)$ using the Jacobian of $y(x)$, yielding:

$$f(x) = g\Big[y(x)\Big] \left|\frac{dy}{dx}\right| = \frac{1}{\sigma\sqrt{2\pi}} \exp\left[-\frac{1}{2\sigma^2}(\ln x-\mu)^2 \quad \left|\frac{1}{x}\right|\right] .$$

Since for all values of y, $x = e^y$ is positive, it follows that:

$$f(x) = \frac{1}{\sigma x\sqrt{2\pi}} \exp\left[-\frac{1}{2\sigma^2}(\ln x-\mu)^2\right] \; ; 0 < x < \infty$$

which is the log-normal distribution.

Figure D-1 displays several log-normal curves with various values of μ and σ. In the normal distribution, μ specifies a location (the mean value) and σ specifies a scale (the standard deviation). In the log-normal distribution μ becomes a scale factor and σ becomes a shape factor.

The log-normal distribution represents many familiar processes. Examples are:

- Distribution of personal incomes
- Size of an organism (simple life forms) whose growth rate is subject to many small impulses (food, light, temperature, cell division, etc.)
- Distribution of particle sizes obtained from breakage (ref., The Mathematical Description of Certain Breakage Mechanisms Leading to the Logarithmic-Normal Distribution, B. Epstein, Journal of the Franklin Institute, 1947).

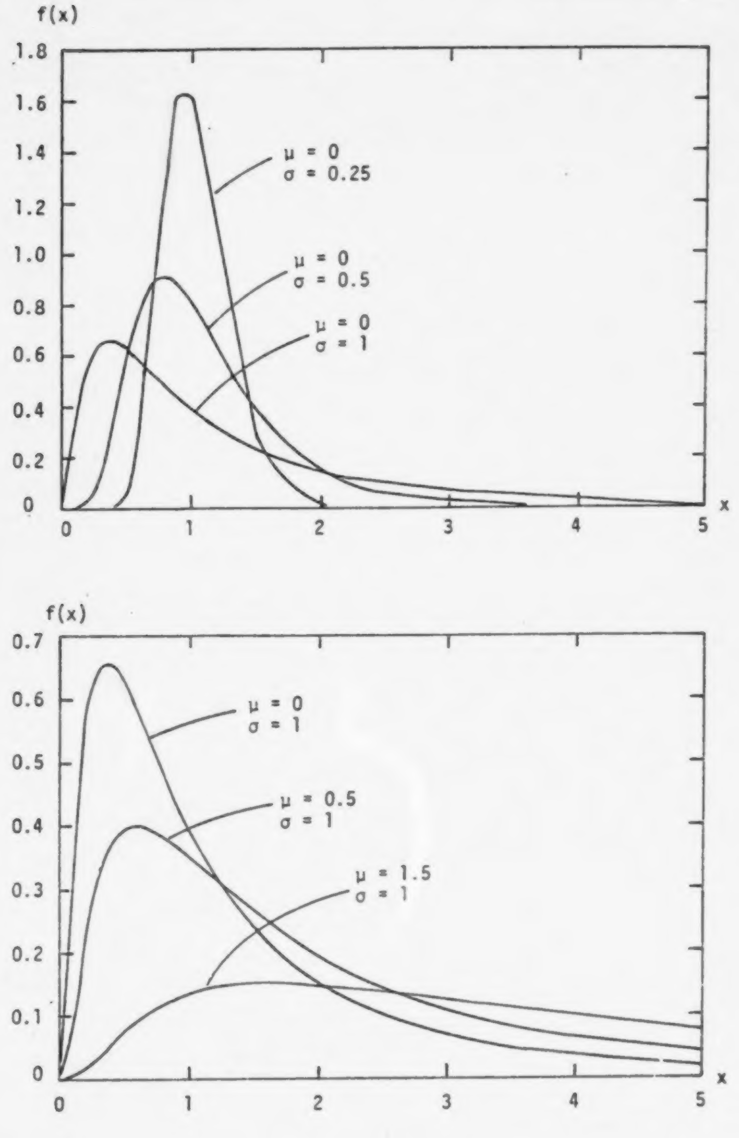


Figure D-1. Log-normal distributions with values values of μ and σ.

The prospect of relating the sizes of oil spills from pipelines to the sizes of particles resulting from dropping a china cup on a tile counter may or may not appeal to one's reason. Certainly, in both cases, it seems evident that there are more small spills than large spills as there are more small china particles (even dust) than large particles. Also obvious: There are no negative spills nor are there negatively sized particles.

The fundamental support of the hypothesis is that the key factors which determine spill size contribute multiplicatively. It is clear that spill magnitude is directly proportional to leak rate and correction shutdown response time. Leak rate is further proportional to the area of the opening in the pipe and the square root of the internal line pressure. Correction time is either proportional to the ratio of leak rate and line flow (if leak detection monitoring is sensitive to leakage as a percent of flow) or simply proportional to leak rate (if detection is based on visual search dependent on leak volume alone). The key factor which underlies the mechanics of the spill process is proportionality:

- The larger the line the larger the spill
- The higher the pressure the greater the leak rate
- The greater the split or opening the greater the leak rate
- The larger the time till detection the greater the spill.

and so on. The exact functional form relating spill size to these factors is not so important. Clearly, these major factors contribute in a multiplicative as opposed to additive fashion. This observation strongly supports the log-normal hypothesis.

D.4.2 Goodness of Fit

Table D-3 (see Section D.3) gives a comparison of actual versus estimated spill frequencies for various spill magnitude ranges. Figure D-2 presents a graphical comparison of the same data. Additionally, Figure D-2 gives the χ^2 values as a measure of goodness of fit for each of the five years (1971-1975) as well as for the five-year totaled values.

The chi-squared (χ^2) goodness-of-fit test is the most commonly used procedure for evaluating distributional assumptions. The use of the test involves grouping observed data into frequency cells. The resulting cell frequencies are compared with the expected frequencies from a proposed distribution. This comparison generates a test statistic which approximates a chi-square variate. The test of the proposed distribution is in the form of a statistical test of the hypothesis that the observed data come from the proposed distribution. As the value of χ^2 (the test statistic) increases the probability that the observed data came from the proposed distribution diminishes. A level of significance is usually established to determine acceptance or rejection of the hypothesis. The level typically adopted is five percent (or .05), meaning that χ^2 values exceeding the .05 level could have occurred,

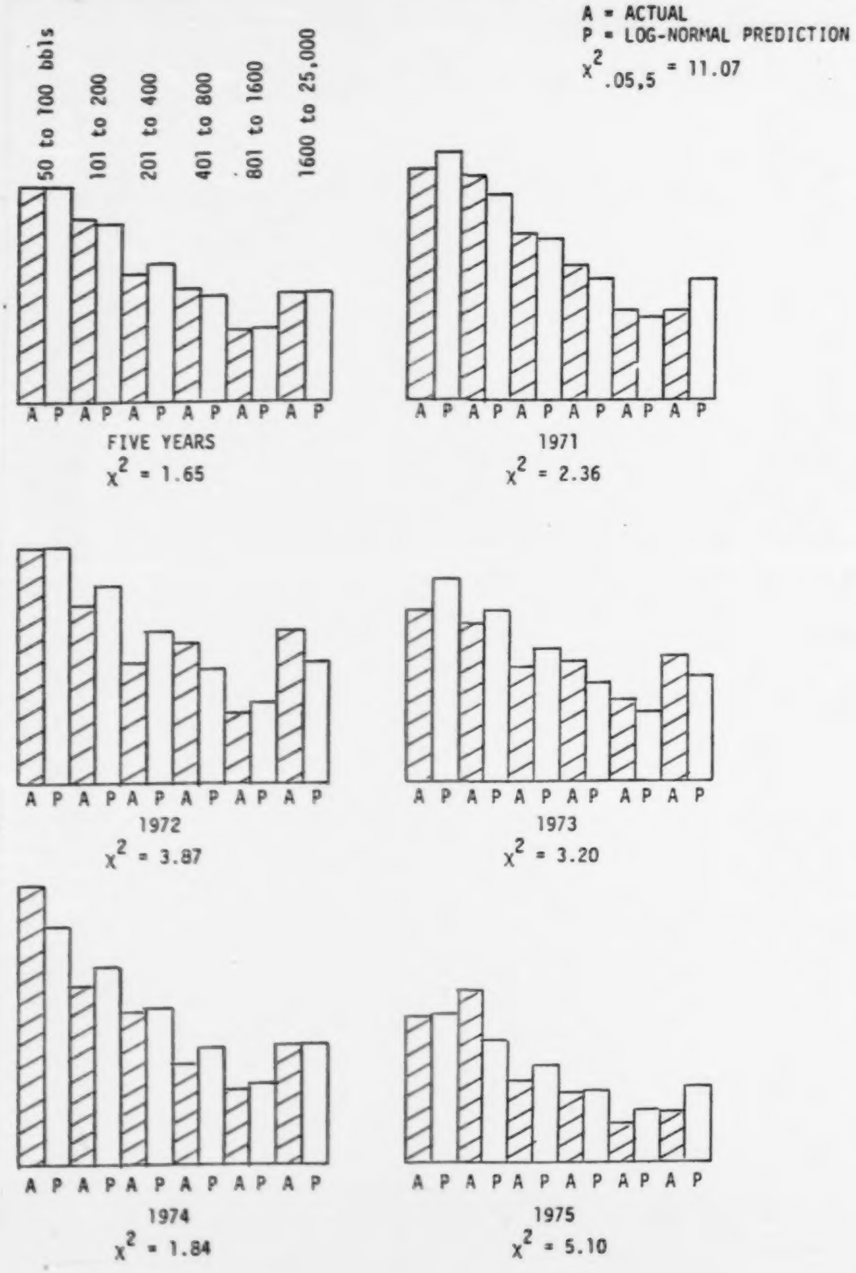


Figure D-2. Comparison of predicted and observed spill-frequencies (crude).

were the hypothesis true, with a chance of less than one in twenty. The χ^2 test statistics are calculated using expression (1), Section D.3.

The χ^2-values for the five years data on spills from crude pipelines, using the log-normal distribution $f(x;\mu,\sigma)$, $\mu = 2.31$, $\sigma = 2.94$, are:

Year	χ^2
1971	2.36
1972	3.87
1973	3.20
1974	1.84
1975	5.10
All five years	1.65

The χ^2 value at the .05 level (five degrees of freedom) is 11.07. It is clear therefore that the proposed distribution provides an exceptional fit of the observed data.

D.4.3 Conclusions

The distribution of spill sizes from U.S. crude pipelines over the five years 1971 through 1975 is reasonably modeled by a log-normal probability density function, ($f(x;\mu,\sigma)$, $\mu = 2.31$, $\sigma = 2.94$. This function is displayed in Figure D-3. The average yearly distribution of spills and barrels lost is given in Table D-4 and depicted by Figure D-4.

Regarding the question of spill frequency below the reporting threshold, it is seen that the frequency of spills increases radically as the spill magnitude decreases. The mode of the log-normal function ($\mu = 2.31$, $\sigma = 2.94$) occurs at about the .0018 barrel (9.7 oz or 286 cc) level. The median occurs at close to ten barrels (almost half of all spills are ten barrels or less) and the average (mean) spill is about 300 barrels.

From Table D-4 it appears that about 70 percent of all spills which occur are not reported, being below the 50 barrel OPS threshold. In terms of volume lost, however, spills in the 0-50 barrel range, while numerous, account for only 2.1 percent of the total spillage from crude pipelines.

D.5 PRODUCT SPILLS

The estimation methodology was applied to product spills from pipeline leaks with similarly favorable results. Table D-5 contains a summary of product spill frequencies for the five-year period covered by the data base. Products included were:

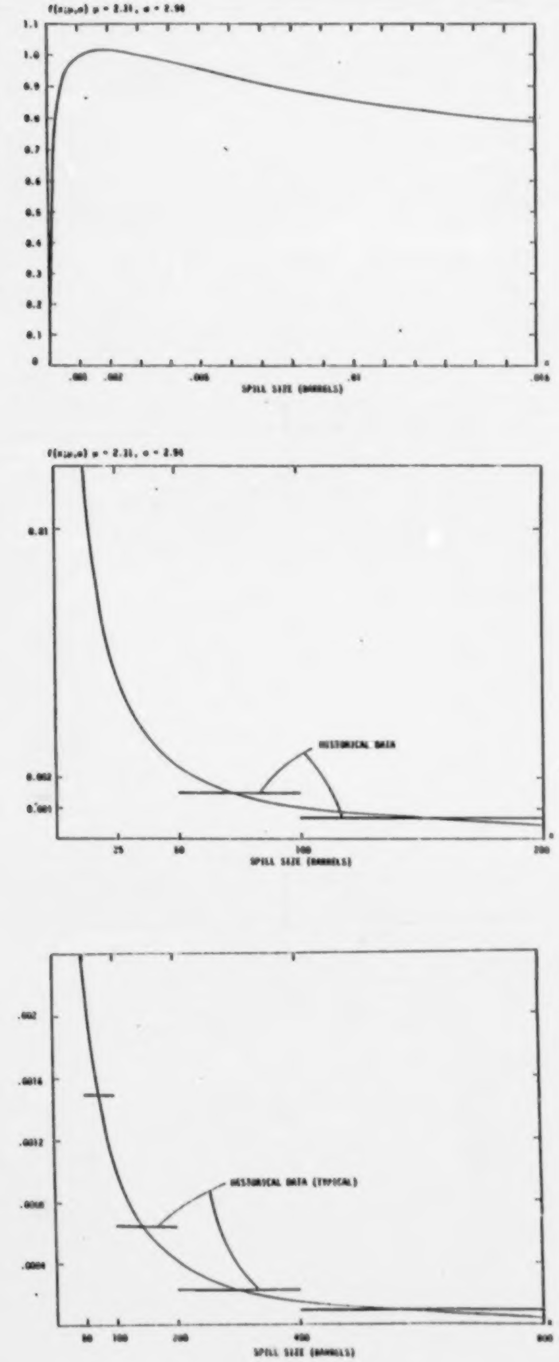


Figure D-3. Log-normal density function.

TABLE D-4. ANNUAL DISTRIBUTION OF SPILL FREQUENCIES, BARRELS LOST (CRUDE)

Range (Barrels)	Frequency	Percent	Barrels Lost	Percent
0 - 10	208	49	548	0[a]
10 - 50	92	21	2,248	2
50 - 100	33	8	2,391	2
100 - 200	28	7	3,969	3
200 - 400	22	5	6,233	5
400 - 800	16	4	9,262	7
800 - 1600	12	3	13,023	10
1600 - 25000	17	4	93,326	71
TOTAL	428		131,000	

[a] Less than 1/2 of one percent.

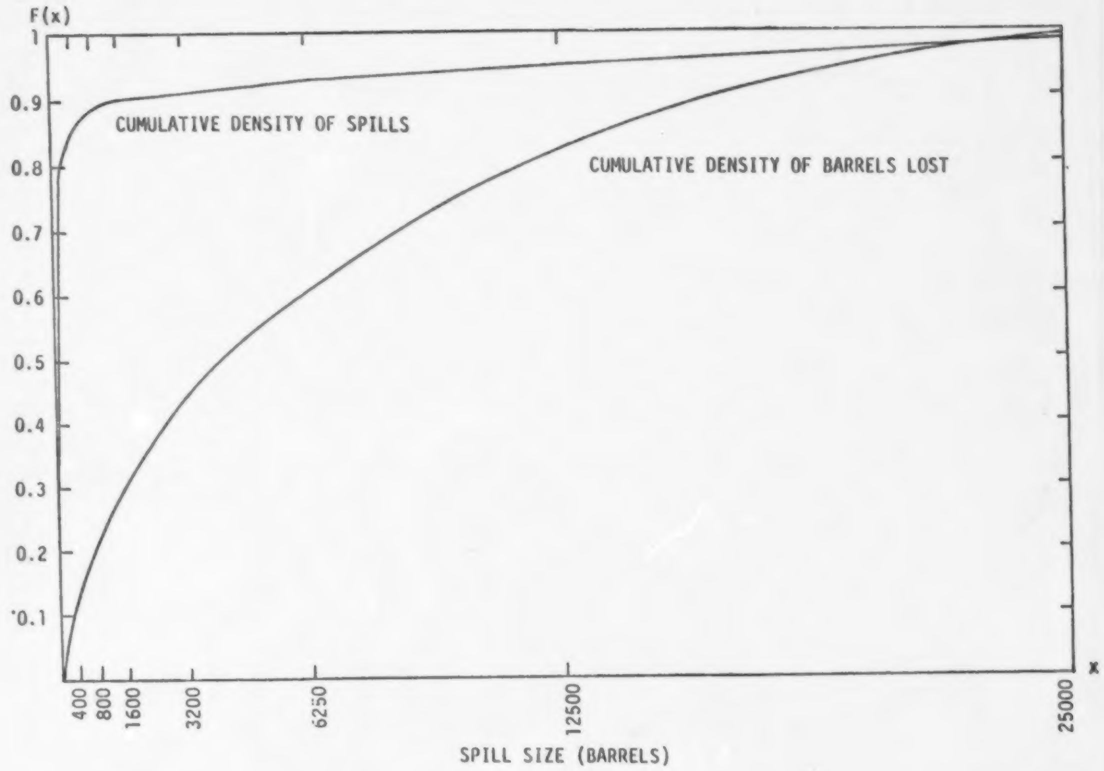


Figure D-4. Cumulative density functions (crude).

TABLE D-5. PRODUCT SPILLS FROM LINE PIPE (NO. OF SPILLS)

Range (Barrels)	1971	1972	1973	1974	1975	5-Year Total
50 - 100	7	8	7	7	9	38
100 - 200	7	14	13	6	11	53
201 - 400	15	14	14	8	17	68
400 - 800	21	18	9	6	9	63
800 - 1600	9	17	6	11	15	58
1600 - 25000	15	13	15	11	15	69
	74	84	64	49	76	347

- Heating/fuel oil
- Kerosene
- Gasoline
- Diesel
- Natural gas liquid/condensate gas
- Ammonia.

As with the estimate for crude, only leaks from the line pipes were considered. Spills or leaks from valves, pumps, tanks, etc. were excluded.

The best log-normal fit to the five-year data was obtained with $\mu = 6$, $\sigma = 1.55$. The goodness-of-fit for the five-year data was even better than the "five-year fit" on the crude data, with $\chi^2 = .70$. Figure D-5 displays the fit of the log-normal distribution to each of the five years. The χ^2 values for each of the years data are:

Year	χ^2
1971	5.71
1972	2.64
1973	3.95
1974	3.88
1975	3.48
All five years	0.70

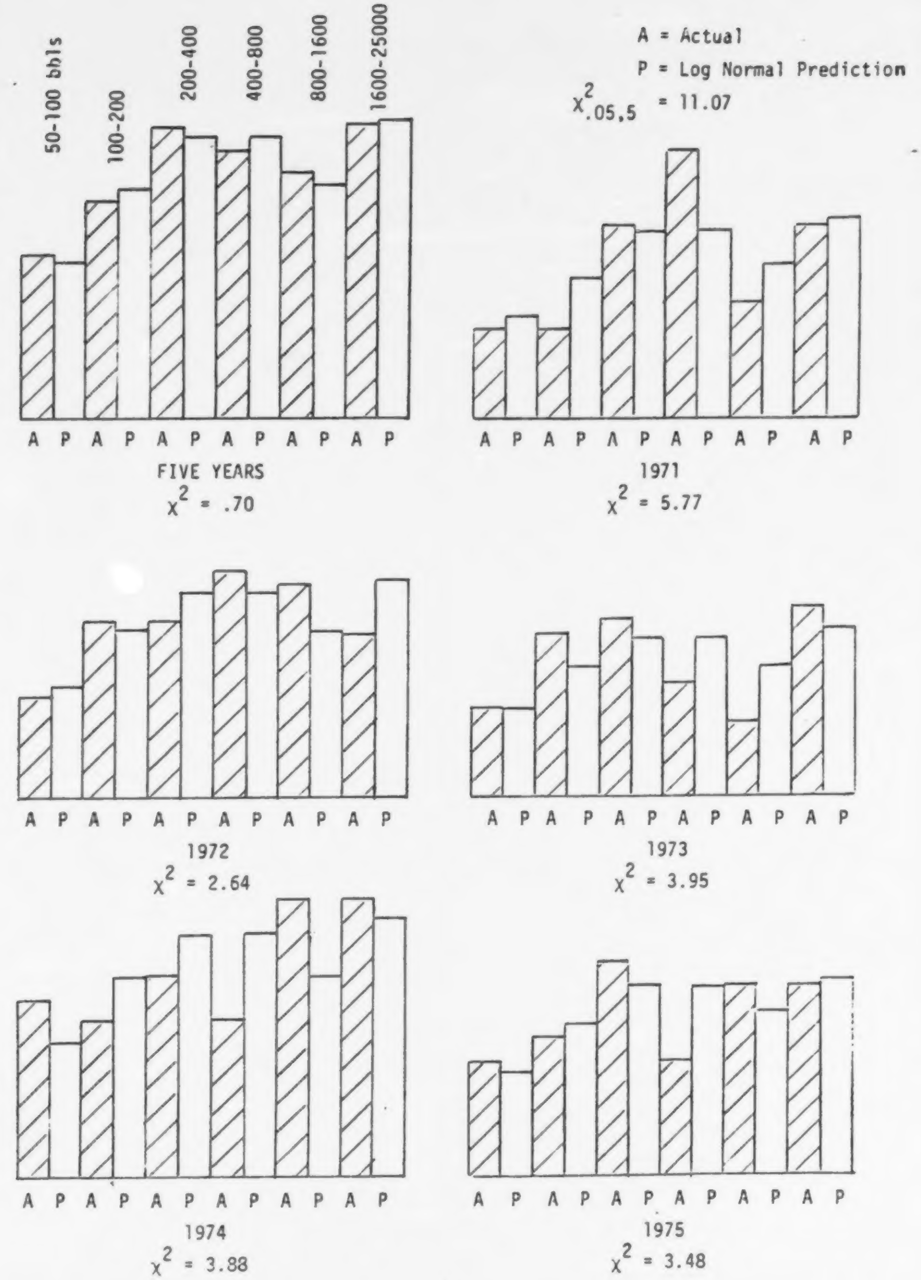
Considering again that the χ^2 value (5 D.F.) at the .05 significant level is 11.07 shows the remarkable fit of the log-normal distribution to the observed data.

Table D-6 provides a tabulated comparison of actual versus recorded spill frequencies. Table D-7 gives the average annual distribution of spill frequencies and barrels lost by spill magnitude ranges.

Figure D-6 depicts the log-normal probability density function, $f(x;\mu,\sigma)$, $\mu = 6$, $\sigma = 1.55$. Figure D-7 gives cumulative density functions for spill frequencies and barrels lost in relation to spill size.

A comparison of the log-normal distributions of crude and product spills is noteworthy. The mode (or peak) of the crude distribution occurs at the .0018 barrel level, while the mode for product spills occurs at 37 barrels. This indicates that crude spills increase in frequency as spill size decreases, almost to zero, while product spills "peak out" at around the 37 barrel level.

The median of crude spills is at about ten barrels, while for product spills the median is at about 400 barrels. While half of all crude spills are ten barrels or less, half of all product spills are 400 barrels or less (or conversely - larger than 400 barrels).



FIVE YEARS
$\chi^2 = .70$

1971
$\chi^2 = 5.77$

1972
$\chi^2 = 2.64$

1973
$\chi^2 = 3.95$

1974
$\chi^2 = 3.88$

1975
$\chi^2 = 3.48$

Figure D-5. Observed and predicted product spill-frequencies.

TABLE D-6. PREDICTED AND ACTUAL SPILL FREQUENCIES (PRODUCTS)

Interval Range	1971			1972			1973			1974			1975			Five-Year Totals		
	Actual	Pred[a]	Barrels	Actual	Pred[a]	Barrels	Actual	Pred[a]	Barrels	Actual	Pred[a]	Barrels	Actual	Pred[a]	Barrels	Actual	Pred[a]	Barrels
0 - 10	--	.7	5	--	.8	5	--	.6	4	--	.5	3	--	.7	5	--	3.3	21
10 - 20	--	1.5	23	--	1.7	25	--	1.3	20	--	1.0	15	--	1.5	23	--	6.8	104
20 - 30	--	1.7	44	--	1.9	48	--	1.5	37	--	1.2	29	--	1.8	44	--	7.9	197
30 - 40	--	1.8	63	--	2.0	70	--	1.5	54	--	1.2	42	--	1.8	64	--	8.1	284
40 - 50	--	1.8	80	--	2.0	89	--	1.5	69	--	1.2	53	--	1.8	81	--	8.0	362
50 - 100	7	8	598	8	9	664	7	7	513	7	5	396	9	8	605	38	36	2,702
100 - 200	7	12	1,757	14	13	1,950	13	10	1,508	6	8	1,164	11	12	1,777	51	54	7,939
200 - 400	15	15	4,240	14	16	4,706	14	13	3,639	8	10	2,809	17	15	4,288	68	66	19,152
400 - 800	21	15	8,405	18	16	9,328	9	13	7,213	6	10	5,569	9	15	8,499	63	66	37,975
800 - 1600	9	12	13,685	17	13	15,187	6	10	11,744	11	8	9,067	15	12	13,838	58	54	61,829
1600 - 25000	15	16	69,645	13	17	77,288	15	13	59,763	11	10	46,142	15	16	70,422	69	70	314,651

[a] Log-normal estimate.

TABLE D-7. ANNUAL DISTRIBUTION OF SPILL FREQUENCIES BARRELS LOST (PRODUCTS)

Range (Barrels)	Frequency	Percent	Barrels Lost	Percent
0 - 50	7	9	194	0
50 - 100	7	9	541	1
100 - 200	11	14	1,588	2
200 - 400	13	17	3,832	4
400 - 800	13	17	7,595	9
800 - 1600	11	14	12,366	14
1600 - 25000	14	18	62,930	71
	76		89,046	

EPA Form 2350-6 (4-80)

TYPING GUIDE SHEET

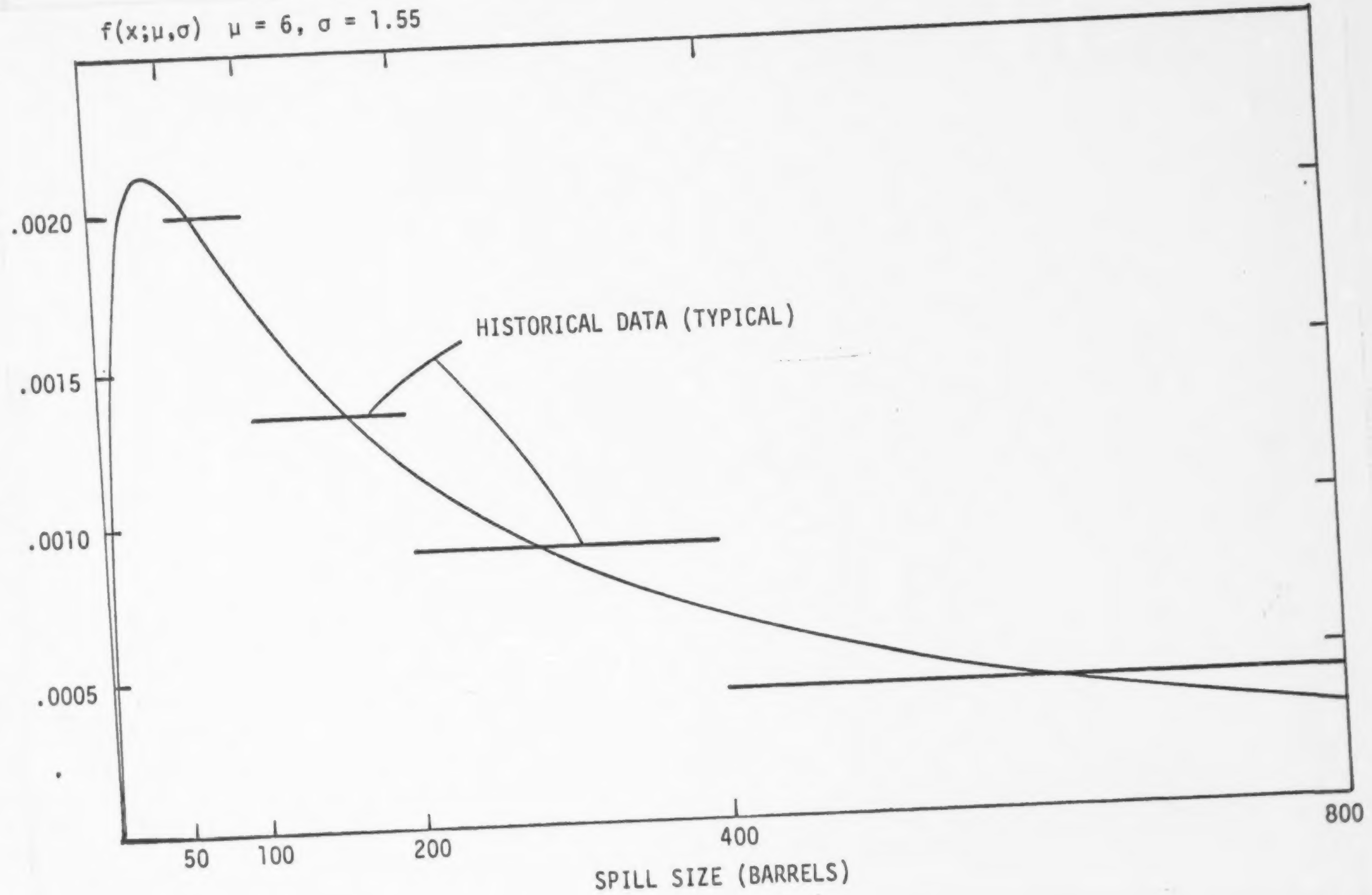


Figure D-6. Log-normal distribution, product spills.

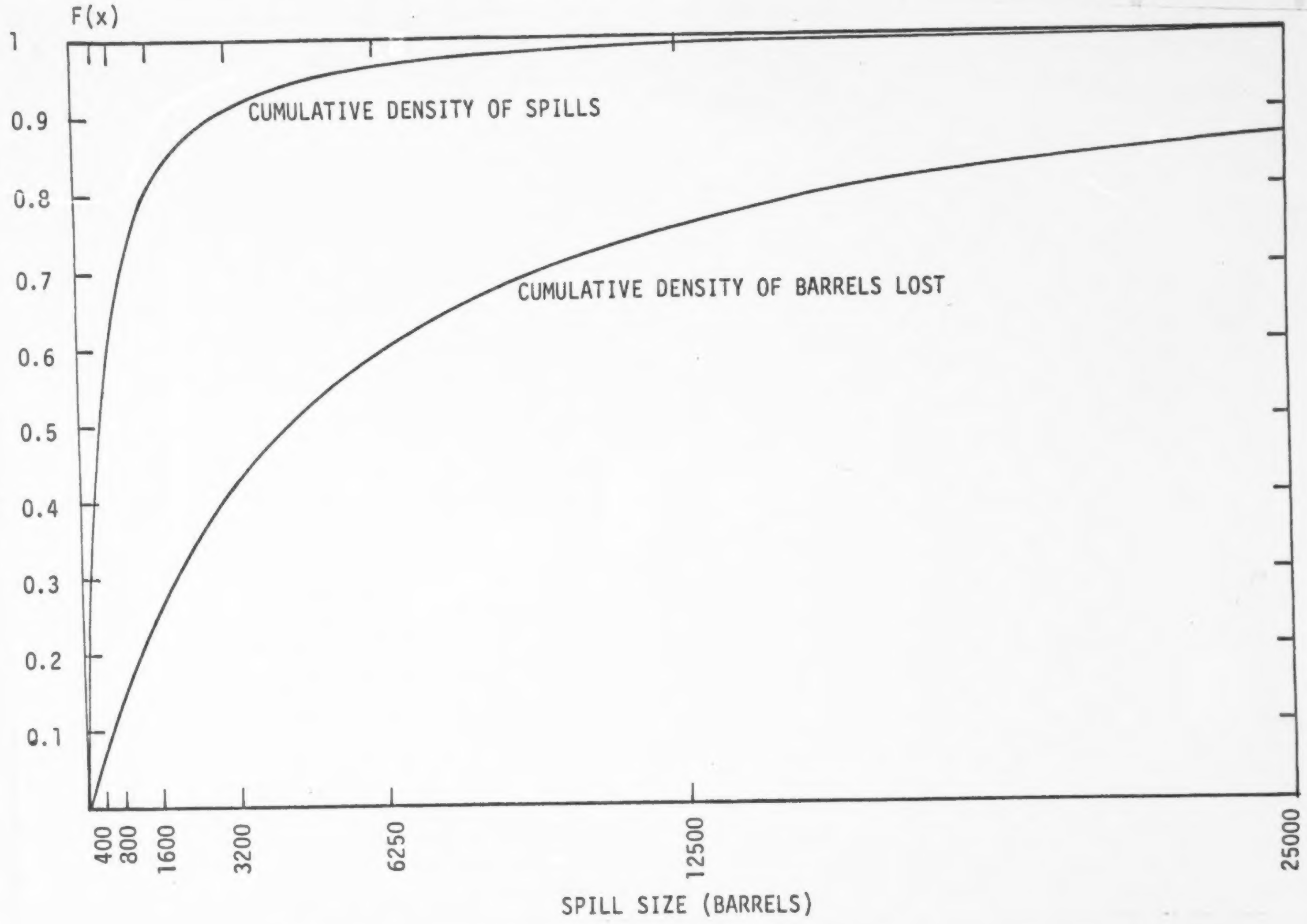


Figure D-7. Cumulative density functions (products).

The average crude spill is about 300 barrels, the average product spill about 1166 barrels. In short, product spills are, on the average, somewhat larger than crude spills. This is an expected result since products are generally lighter and less viscous than crude.

APPENDIX E

METHODOLOGY

E.1 VISUAL AND AIDED VISUAL LINE OBSERVATION

E.1.1 Visual Inspection by Air or Ground Level

(See Table 46 methods (a) through (f) and Sections 5.3.2.1 and 7.3.1.3.)

E.1.2 Visual Inspections by Ground Patrol with Hydrocarbon Detector or Other Comparable Device

(See Table 46 method (h) and Sections 5.3.2.1, 5.3.2.4 and 7.3.1.1.)

E.2 OIL SPILL DETECTORS ON OR NEAR THE WATER

E.2.1 Oil Spill Detectors

(See Table 47 (c) and Sections 5.3.2.2 and 7.3.1.2.)

E.3 INTERNAL FLUID VARIATIONS DURING TRANSFER

E.3.1 Pressure Deviations

(See also Table 48 (a) and Sections 5.3.2.3 and 7.3.1.3.)

Principle of Operation

The pressure deviation of leak detection methods basically involve continuous monitoring by computer of line pressure at various locations along the pipeline is carried out during oil transfer. If pressure deviations (i.e., pressure drops, etc.) are excessive and exceed a set point value, system alarms are generated.

Sensitivity

Pressure deviation inspection is most sensitive for large leaks close to the discharge pumps and close to the downstream end of the pumping stations. At locations where the line pressures are low, such as upstream of the pumps, large leaks cause small pressure drops that are difficult to detect.

Manufacturer and Costs

All necessary equipment and components for typical pressure deviation inspection systems are commercially available. Total system costs are generally much lower than other continuous leak monitoring methods used during petroleum transfer.

Advantages

This is a commonly used inspection method for detecting large leaks. It is simple to implement.

Disadvantages and Limitations

It is extremely difficult to detect small leaks using this inspection method. Because of the principle used and equipment limitations, the following items (and others) contribute to the poor sensitivity of this method:

- Variations in input or output tank heads
- Changes in fluid properties
- Changes in temperature
- Flow variations affect line pressure drop because pressure drop varies as the flow rate squared
- Leaks are inadvertently compensated for by pressure control valves operating slightly when a system is operating at maximum capacity under pressure control
- Setpoints are usually set very high to prevent false shutdowns. In these instances, only very large leaks or ruptures can be detected.

E.3.2 Flow Rate

E.3.2.1 Comparison--

(See also Table 49(c) and Sections 5.3.2.3 and 7.3.1.3.)

Principle of Operation

Flow rate comparison inspection detects pipeline leaks by measuring the difference in the rate of flow at two locations. Computer systems are available that can continuously compare flow rates every few seconds and generate an alarm when deviations exceed a setpoint value (one percent to five percent of normal flow rate). Alarm levels are usually set to take into account changes in pumping rate, temperature or density of the oil, etc. A variety of transducers that provide signals proportional to rate of flow are commercially available. The most commonly used types include ultrasonic, turbine, and orifice transducers.

Capability

This leak detection equipment is generally used to inspect for large leaks in the pipeline. The method generally works best on lines where the flow is relatively stable.

Manufacturer and Costs

Flow rate comparison systems are commercially available from a number of manufacturers. Costs vary widely depending upon line location and dimensions, transducers, and the required accuracy and automation. Typical manufacturers of systems include Daniel Industries, Adec, Inc., and Waugh Controls, etc.

Advantages

This inspection method is widely used and provides rapid detection of large leaks.

Disadvantages and Limitations

The method can only be used to detect major oil leaks. Also, there is a tendency by operators to raise setpoints to reduce the possibility of alarms and thus decrease leak sensitivity.

E.3.2.2 Flow Rate Deviation--

(See Table 48(d) and Sections 5.3.2.3 and 7.3.1.3.)

The flow rate deviation method provides continuous leak detection of the pipeline by measuring the deviations in flow rates at specific flow stations. If the Δ flow rate exceeds a certain value (for example, unexplained changes of normal flow rate (one to five percent)), a leak alarm is generated.

This leak detection is similar to the flow rate comparison except that a comparison of flow rate at another flow station is not required.

E.3.3 Volume Comparisons (Balance)

(See also Table 48(b) and Sections 5.3.2.3 and 7.3.1.3.)

Principle of Operation

A variety of volume comparison techniques for detection of leakage is commonly used in the pipeline oil transportation industry. The basic operation is to measure the input volume, output volume and line pack to check metered barrels into the pipeline against barrels measured out. These measurements are generally based on the following equation:

$$V_L = V_i - V_o + \Delta V_s$$

where

V_L = leak volume during time t

V_i = volume of liquid put into system during time t

V_O = volume of liquid taken out of system during time t

ΔV_S = change in volume of liquid in pipe and tanks in system.

Corrected flowmeter readings are used to provide measurements of V_i and V_O at the input and output. V_S is usually computer corrected for line pack effects by measurements of temperature and pressure at various locations on the pipeline.

If the line is leak-free, no crude is lost. Volumes can be measured by meters (i.e., turbine flowmeters, etc.) and by tank gages. The metering system provides the required volume data with the computerized supervisory control system automatically gathering, comparing and correcting for various parameters (temperature, pressure, density of crude, etc.). Computerized control systems are used that make continuous volume comparisons over typical time intervals ranging from every few minutes to every one to two hours. An alarm is generated when a volume comparison difference exceeds a predetermined setpoint. Settings are made taking into account corrected volumes and system tolerances in transducers, electronics, power variations, etc.

Capability

This leak detection equipment is used primarily to inspect for large leaks in a short period of time and small leaks over a long period of time.

Manufacturer and Costs

Volume comparison systems are commercially available from a number of manufacturers. Costs vary widely depending upon line locations and dimensions, transducers, and the required accuracy and automation. Typical manufacturers of systems include Adec, Daniel, Siemens, and Waugh.

Advantages

Equipment can be used on an almost continuous basis. Systems can be automated to provide simple operation. Major leaks can be detected in a short period of time.

Disadvantages and Limitations

Some of the main disadvantages and limitations of this method for inspection purposes are:

- Detects leaks after they occur
- Difficult to detect slow leaks that over a period of time may result in a major oil spill
- Cannot detect a catastrophic failure in sufficient time to prevent a major oil spill
- Tendency by operators to raise setpoints to reduce alarms because of line pack and other considerations
- Detects leaks only about once per hour for most commonly used systems.

E.3.4 Mathematical Modeling

(See also Table 48(f) and Sections 5.3.2.3 and 7.3.1.3.)

Principle of Operation

Mathematical modeling is a real-time computerized pipeline monitoring method for detection of small amounts of oil leakage; only losses in the inventory are of interest and the inspection is a form of dynamic inventorying of the pipeline product. The method is affected by solving momentum and continuity equations for a specified pipeline and/or hose string network. The differential equation that results is solved by iterative methods with suitable techniques so that the mathematical model is run in real time and can be trimmed as required to fit the actual pipeline. Mathematical models are available that fit the pipeline during start-up and compensate for transients such as pump start-up, shutdown, valve closures, water-hammer effects, etc. that normally occur in the pipeline. In addition, models can provide accurate means of compensating for line pack due to product compressibility, in pipe-wall and hose-wall deformation.

Modeling methods require that a significant amount of information be known and a variety of measurements made continuously. These include product information (density, viscosity, etc.); pipeline dimensions and materials; valving; and product propagation information (flow and pressure at both ends of pipeline, temperature gradient of the product, etc.).

Capability

Mathematical modeling can be used for continuous leak inspection of the pipeline. The method also can be used during static or hydrostatic leak tests.

Sensitivity

Estimated sensitivity is about 0.1 percent of the flow rate at the time the leak occurs. For example, if 100,000 barrels per hour is offloaded, a 100 barrel per hour leak can be detected.

Manufacturer and Costs

Mathematical modeling systems for leak detection inspection are commercially available from a few companies. The leak detection equipment is in current use on oil pipelines. Costs are typically less than one-half percent of the cost of the pipeline. Costs are even lower if the equipment can be used with existing supervisory control systems.

Advantages

Some of the main advantages of this inspection method are:

- Computerized reduction
- Good failure detection
- Provides leak detection improvements over conventional hydrostatic pressure tests
- Can be used in conjunction with supervisory control systems
- Requires only repeatable rather than high accuracy flow meters
- Limited continuous inspection.

Disadvantages and Limitations

One disadvantage is that the leak can only be detected after the flow reaches a meter. Hence, for long distances between meters significant spillage can occur for large leaks or ruptures before detection.

This method is new and not totally proven on a large number of lines. Although automatic, it may require trained personnel to properly interpret results or maintain the system. Commercial availability of these systems is limited because of the small number of companies currently involved in this area.

E.3.5 Negative Pressure Surge

(See Table 48(j) and Sections 5.3.2.3 and 7.3.1.3.)

E.4 DETECTION AND LOCATION OF LEAKED OIL ON OR AT A SHORT DISTANCE FROM PIPELINE

E.4.1 External Rods with Passive Acoustic Sensor

(See Table 48(n) and Sections 5.3.2.4 and 7.3.1.4.)

E.4.2 Passive Acoustic Array

(See also Tables 49(o) and 55(a) and Sections 5.3.2.4 and 7.3.1.4.)

Principle of Operation

Experimental results have shown that acoustic signals generated in pipeline from external impacts, excessive internal stresses from material defects and damage, precursor internal stresses just before a leak or material failure, are all different; each event produces a characteristic signal that can be differentiated from the other. These acoustic signals are commonly called "acoustic emissions" and are excellent indicators of incipient failure. Generally, these acoustic emissions, except for external impacts, are repetitive. Repetition rate usually increases to a peak value, then drops off slightly, and then increases dramatically just before a critical material failure or leak occurs. The acoustic emissions only occur when the component is stressed - externally loaded or pressurized. Acoustic emission signals are complex, dependent upon structure and fault type and the frequency typically extends to the megahertz range.

The same acoustic system that is used to detect the continuous waves generated at a leak source and which propagate along the pipeline can, with additions to the signal processor, be used to detect the acoustic emission signals. Using known wave attenuation characteristics of the pipeline, and also using suitable signal enhancement, counting, and processing technique, the location and condition of the flawed area may be determined.

Capabilities

Passive acoustic array inspections using acoustic emissions potentially can be applied to effectively reduce oil spill risks by continuously monitoring the pipelines for actual failures (leaks) and impending failures (internal defects that may lead to a failure).

Sensitivity

Defect location depends upon a variety of factors such as pipeline material, size and length, acoustic transducer design and spacing, and signal processing techniques. Additionally, hydrostatic tests can be used advantageously to enhance the internal defects so that such defects can be detected, whereas such defects it might not be detected at normal operating and flow conditions.

Advantages

Some of the main advantages of this inspection method are:

- Excellent potential for incipient failure detection
- Computerized automatic system can be adapted to existing supervisory control systems
- Commercial system currently available for similar applications such as periodic proof testing of tanks, pressure vessels, etc.
- Permanent records

- Continuous monitoring

- Locates defects for more detailed inspection by other means.

Disadvantages and Limitations

The main disadvantage and limitation of acoustic emission leak detection is that incipient failure data is subject to interpretation as to the severity of the defect and how long before the defect grows to a critical size and then causes a rupture, leak, etc. Also, system effectiveness and performance specifications are uncertain.

Applications

Two slightly different passive acoustic array systems (see Section 7.3.1.4) are selected in this study for two main applications. The first system is for installation on new lines or on lines located in high risk areas such as underwater. Such systems are expected to be highly sensitive and capable of detecting most impending failures and leaks including outside force damage and ruptures. The second system is for retrofit installations. These types of systems are of lower sensitivity but expected to be capable of providing prevention of failures by detecting damage by outside forces and minimizing spill size by detecting ruptures.

E.4.2.1 Passive Acoustic Array - Systems for New Lines--

(See also Sections 5.3.2.4 and 7.3.1.4.)

Installation

Acoustic sensors with signal conditioning equipment are expected to be installed at approximately five locations each mile. A multiconductor cable, running the length of the line provides both power and transmission of the signal from each acoustic sensor. Master units supply the power, signal processing and control. These units would typically be located at each pump station and two locations between each pump station.

Capabilities

Systems are expected to be capable of both preventing most failures and early detection of most leaks. Capabilities include detection of outside forces, damage, internal defects, small leaks and ruptures.

E.4.2.2 Passive Acoustic Array - Retrofit Systems--

(See also Sections 5.3.2.4 and 7.3.1.4.)

Installation

Acoustic sensors would be installed at the pump station and at various locations, typically at four stations (approximately ten miles apart), between each pump station. Signal conditioning and telemetry would be used for remote monitoring of sensor signals.

Capabilities

Systems are expected to be capable of detecting damage by outside forces and rupture detection.

E.5 PERIODIC PRESSURE TESTS

E.5.1 Pressure Static

(See also Table 50(a) and Sections 5.3.2.5 and 7.3.1.5.)

Principle of Operation

The pipeline is operated in an intermittent manner at nominal operating pressure; static pressure measuring techniques are used to detect a leak when sections of the line are closed off and shut down. If the pressure holds, the line is considered tight. High accuracy pressure gages are used to monitor the line pressure. High leakage rates (i.e., greater than 500 l/hr) can be detected over short time intervals (about 15 minutes) by measuring the static pressure drop. Detections for lower leakage rates require that effects such as temperature be taken into account by waiting until the temperature stabilizes.

Advantages

This is a commonly used inspection method that is of low cost, simple to implement.

Disadvantages and Limitations

Some of the main disadvantages and limitations are:

- Requires leak detection method if leaks are located
- Variations in temperature, etc. limit sensitivity of leak inspection
- Difficult to detect slow leaks
- Less sensitive than hydrostatic pressure difference method.

E.5.2 Hydrostatic - Pressure Drop and Pressure Difference

(See also Table 50(b) and 50(c) and Sections 5.2.2.5 and 7.3.1.5.)

Principle of Operation

The pressure drop method of inspection uses pressure difference gages that are installed across a series of block valves that isolate sections of an empty pipeline or hose string. The empty sections are then pressurized, typically to 600 psi. Pressure difference gages will indicate if a leak exists after a suitable period of time. Actual stabilization time depends upon the required tightness (leak rate allowed) of the system and temperature effects. Usually, a derivative $d\Delta P/dt$ is used to show the deviation of differential pressure as a function of time in order to simplify conclusions of leakage. Numerous types of pressure difference gages are commercially available for this measurement.

Variations of this inspection method can be made. One variation is to pressurize the line with gases such as helium and detect leaky areas with helium leak detectors. Passive ultrasonic detectors and the passive acoustic array can also be used to detect escaping gas. In another variation, the line could be pressurized and sections of the line closed off. Then the static pressure of each section could be accurately measured. This method can give, to some extent, incipient fault detection. Stresses from proof pressures slightly above normal may cause leaks to prematurely occur and be detected; these leaks, however, would have eventually occurred because of corrosion or other effects at some later time at normal operating pressures.

Advantages

This inspection method is simple, provides good incipient failure detection and is a widely used inspection technique. It is a high cost inspection since the system must be shut down.

Disadvantages

Some of the main disadvantages of this inspection method are:

- Requires out-of-service operation
- Potentially can cause damage to pipeline components if test pressure is excessive
- Requires leak detection method to locate leak
- Downtime required because of time for temperature stabilization can be of long duration (24 to 72 hours)
- High cost to retrofit.

E.6 CORROSION INSPECTION

E.6.1 Change or Add Inhibitors as Needed

(See Sections 5.2.2.6 and 7.3.1.6.)

E.7 STANDARD NON-DESTRUCTIVE TESTING

E.7.1 Inspection of Sample of Line for Wall Thickness

Changes by ultrasonics or comparable technique (see Table 52(a) and Sections 5.2.2.7 and 7.3.1.7).

E.8 INSPECTION PIGS

E.8.1 Magnetic Flux Inspection Pigs

(See also Table 53(a) and Sections 5.2.2.8 and 7.3.1.8.)

Principle of Operation

A magnetic field is induced into a pipe wall around the circumference and the field flows in a longitudinal direction. In an undamaged pipe, a smooth flow of magnetic lines of flux all remain within the pipe body wall. A damaged or unnatural area of the pipe affects the flow of the lines of flux and causes the flow to "bridge" across this area and create a magnetic disturbance or flux leakage. This flux leakage is proportional to the size and depth of the damaged area.

One of the most widely used magnetic flux inspection pigs is the AMF Tuboscope Linalog. The instrumented pig uses electromagnets to induce the magnetic field and it is sent through the pipelines, typically at a few miles per hour, propelled by oil or water flowing through the pipeline. This device is expected to be operated in salt water next year. A magnetic tape recorder is installed in both inspection pigs and is used to store the electromagnetic data. Data tapes are then reduced and analyzed after the pigs are run through the pipeline.

Capability

Magnetic flux inspection pigs are the most widely used type of inspection pigs. The most important capabilities of the device is that it can be used to measure the severity of corrosion. It can also be used to inspect for a variety of pipeline defects including hardspots, manufacturing defects and flaws, girth welds, gouges, pits, etc. Additionally, the device can be used to help evaluate the effectiveness of the cathodic protection system.

Sensitivity

The sensitivity of the magnetic flux inspection pig is quite good for corrosion or pitting. Typically it is graded in three ranges of corrosion severity: 15-30 percent of nominal wall; 30-50 percent of nominal wall; greater than 50 percent of nominal wall. Defects as small as 1/8 are claimed as detectable by the manufacturers.

Manufacturer and Costs

The two main manufacturers of these magnetic flux inspection pigs are AMF Tuboscope, Inc. and Vetco Pipeline Services. A similar type of inspection pig is currently under development in Canada.

These devices are usually provided as an inspection service that includes inspection pig, operating personnel and data analysis. A typical cost for inspection of 20 miles of 36" pipeline is about $20K.

Advantages

Advantages include the following:

- High reliability
- Locates defects
- Permanent record
- Monitors integrity of line
- Locates potential failures before they reach catastrophic failure
- Helps evaluate effectiveness of cathodic protection
- Commercially available.

Disadvantages and Limitations

For maximum effectiveness, frequent inspection, once or twice a year, are desireable. Hence, high inspection costs normally limit the number of inspections.

Data records are difficult to interpret and require human interpretation. It is also possible to have anomalies that are difficult to interpret. For example, a weld that penetrates into pipe may result in cavitation downstream causing corrosion and erosion. The girth weld would be picked up but the adjacent anomalies may not show up because the operator may be monitoring only one pulse from the device in that area.

The electromagnetic type cannot determine if a defect is in the inside or outisde of a pipe. The permanent magnet type can get stuck in a pipeline and is difficult to remove without cutting out a section of the pipeline. Both devices do not adequately detect thin cracks.

E.9 SURVEY-PIPELINE SYSTEM CHARTING AND DEPTH OF BURIAL

E.9.1 Depth of Cover by Sonar or Other Comparable Techniques

(See Table 54(b) and (c) and Sections 5.2.2.9 and 7.3.1.9.)

E.9.2 Charting of Line Pipe

(See Table 54(e) and (f) and Sections 5.2.2.9 and 7.3.1.9.)

E.10 MISCELLANEOUS

E.11.1 Preventive Program for Outside Forces

(See Reference 12.)

E.11.2 Passive Acoustic Array

(See Section 5.3.2.10.)